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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE INVESTIGATION OF FINANCIAL DISINCENTIVES TO INVESTMENT IN ENERGY EFFICIENCY BY IDAHO POWER COMPANY	CASE NO. IPC-E-04-15 INVESTIGATIVE WORKSHOP STATUS REPORT

BACKGROUND

On May 25, 2004, The Idaho Public Utilities Commission (Commission) in Order No. 29505 (Idaho Power Company general rate case No. IPC-E-03-13) determined that a separate "proceeding to assess financial disincentives inherent in Company-sponsored conservation programs is appropriate and should proceed by informal workshops." The Commission's Order provided in relevant part as follows:

> The Commission specifically directs the parties (Idaho Power, NW Energy Coalition, Industrial Customers of Idaho Power (ICIP) and Commission Staff) to address possible revenue adjustment when annual energy consumption is both above and below normal. The parties should also consider how much adjustment is necessary to remove DSM investment disincentives and whether (and to what extent) performance-based incentives such as revenue sharing could or should be incorporated into the resolution of this issue. The Commission is interested in proposals that could provide Idaho Power the opportunity to share and retain

> benefits gained from efficiencies, especially technologies... In short, the Commission believes opportunities exist for improvements in operating efficiency that would benefit the Company shareholders and its customers, and we encourage the parties to creatively consider the options for a performance-based mechanism to present to the Commission. *The parties to the agreement are directed to propose a workshop schedule and initiate a proceeding.* (emphasis added)

Order No. 29505 at pp. 68, 69.

As a follow up to the Commission's Order, the NW Energy Coalition on June 18, 2004 formally requested that a proceeding be initiated and that a workshop schedule be established. The Commission in Order No. 29558 established this docket to investigate the financial disincentives which hinder Idaho Power's investment in cost-effective energy efficiency resources. The Commission stated that the scope of the investigation should be focused on decoupling and performance based ratemaking. The Commission directed the participating parties to provide a written report to the Commission no later than December 15, 2004 updating the Commission on the status of the investigative workshops.

PROCESS

The parties have participated in five workshops to date: August 24, September 27, November 8, December 1 and December 13, 2004. Workshops have included presentations by participants, group discussion, and assessment of areas of agreement and disagreement. Susan Hayman with North Country Resources, Inc., a Boise-based facilitation/mediation firm, prepares agendas and facilitates workshops. Four designated workshop coordinators representing each of the four major interests at the table (Idaho Power Company, Idaho Public Utilities Commission Staff, Industrial Customers of Idaho Power, and Northwest Energy Coalition) cooperate in designing workshops. Copies of workshop summaries for all but the December 13, 2004 workshop are provided as attachments to this Status Report. When the summary for the December 13, 2004 workshop is completed, it will be provided to the Commission as a supplement to this filing.

PARTICIPANTS

The following people have attended one or more workshops, receive meeting materials and summaries, and are considered active workshop participants:

Name and Affiliation	Name and Affiliation
IPUC Staff	**Northwest Energy Coalition**
Lynn Anderson	Nancy Hirsh, NW Energy Coalition
Randy Lobb	Bill Eddie, Advocates for the West
Terri Carlock	Ralph Cavanagh, Natural Resources Defense Council
David Schunke	
Scott Woodbury	
Idaho Power	**Industrial Customers of Idaho Power**
Ric Gale	Peter Richardson, Industrial Customers of Idaho Power
Bart Kline	David Hawk, J.R. Simplot Co
Maggie Brilz	Don Reading, Ben Johnson Associates
Darlene Nemnich	
Greg Said	**Other Interested Parties**
Tim Tatum	Brad Purdy, Community Action Partnership Association of Idaho
Mike Youngblood	Laura Nelson, IPUC Policy Strategist

PROGRESS

Since the inception of the workshops on August 24, 2004 the signatories to this report have achieved the following:

1) Established and accepted a set of operational principles that guide the workshops;
2) Clarified the nature and extent of financial disincentives to Idaho Power for investment in energy conservation through demand-side management programs (DSM);
3) Agreed that material financial disincentives do exist and will increase as DSM expenditures increase. Not all participants agree that restoration of lost fixed cost revenues would directly result in additional investment in DSM programs by Idaho Power;
4) Agreed on a set of evaluation criteria by which to compare and contrast potential mechanisms for removing financial disincentives and/or providing incentives for DSM programs;

5) Agreed to continue exploring two specifically proposed mechanisms: A true-up mechanism (referred to as a decoupling mechanism in early workshops) and a performance-based incentive mechanism;
6) Agreed to design a true-up mechanism simulation and a pilot program performance-based incentive mechanism to evaluate the effects of these two mechanisms. The simulation and pilot program will be the subject of further review and discussion at the next workshop.

TIMELINE

Participants established the following timeline at the December 1 workshop:

1) Provide this status report to the Commission on or before December 15, 2004, as specified in Order No. 29558;
2) Provide a full report to the Commission no later than January 31, 2005, including participant recommendations and rationale.

This Status Report to the Commission has been reviewed and approved by Idaho Power Company, Northwest Energy Coalition, the Commission Staff and the Industrial Customers of Idaho Power.

12-14-04
Date

Barton L. Kline
Attorney for Idaho Power Company and on behalf of Northwest Energy Coalition, the Commission Staff and the Industrial Customers of Idaho Power

ASSESSING FINANCIAL DISINCENTIVES AND RESOLUTION OPPORTUNITIES, WORKSHOP #2

SEPTEMBER 27, 2004, 9:30 A.M. TO 12:30 P.M.
IDAHO POWER CORPORATE HEADQUARTERS, BOISE, ID

Facilitation	Susan Hayman, North Country Resources, Inc.
Documentation	Natalie Chavez, Chavez Writing & Editing, Inc.

WORKSHOP OBJECTIVES

1) Develop operational protocols for the remaining workshops
2) Continue investigating the nature and extent of financial disincentives to energy conservation programs (DSM)
3) Explore a potential decoupling mechanism to address DSM investment disincentives

WORKSHOP DECISIONS AND OUTCOMES

The next meeting will be held November 8, 2004, from 9:30am - 3:30pm at IPC. The morning will be spent reviewing results of action items 1 through 3 (below), while the afternoon will be reserved for discussing performance-based incentives.

ACTION ITEMS

1) Run a model of the following: a) IRP—rate impacts by class b) NWPCC—rate impacts by class c) Estimate of savings from conservation (using Aurora)	Randy Lobb, Ric Gale, and Ralph Cavanagh
2) Discuss development of a tool to poll customers about energy-conservation/efficiency programs.	David Hawk and Ric Gale
3) Recalculate numbers with an interim rate case but in the absence of a true-up mechanism.	Lynn Anderson
4) List ideas for possible performance-based incentives, and develop a "strawman" if an idea stands out.	All
5) Make requested changes to "Operational Protocol" and to "Definitions." E-mail revised documents to participants.	Susan Hayman

WORKSHOP OPERATIONAL ISSUES

Susan Hayman welcomed participants (Appendix 1), had them introduce themselves, and then reviewed the agenda (Appendix 2). Participants had no changes to the agenda. Hayman had compiled an operational protocol for the series of workshops, based on conversations she had with participants. The group reviewed and made the following revisions to (decisions about) the operational protocols for the workshops (Appendix 3):

- Workshop Purpose statement 1—add "and customers" to the end of the clause
- Workshop Purpose statement 2—retain "performance-based ratemaking" since that language appeared in the IPUC order (Order No. 29558, p. 2), but add "incentives" in parentheses following that phrase

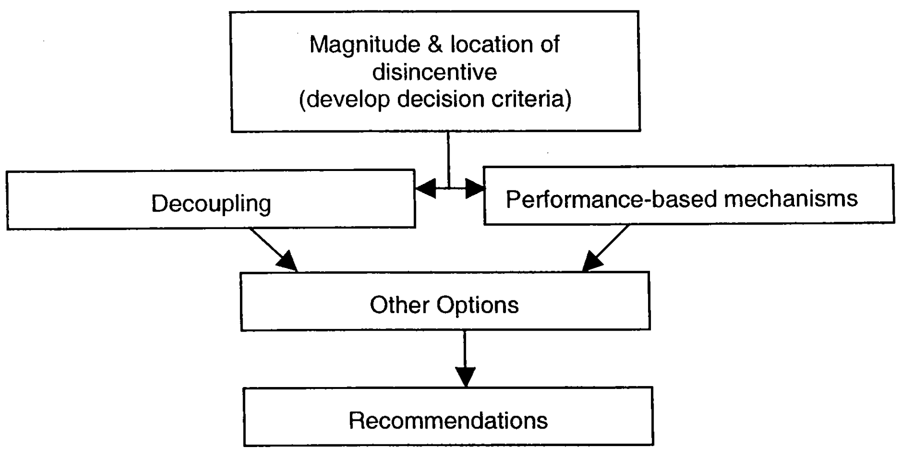
- Roles and Responsibilities statement 2f—designate coordinators: IPC–Mike Youngblood, IPUC–Lynn Anderson, NWEC–Bill Eddie, and Industrial Customers–Peter Richardson
- Analysis statement—replace the question with "Analysis needs will be identified and assigned as they emerge."

Hayman also provided a definitions list for review (Appendix 4). Following are the revised definitions for "demand side management" and "true-up." Definitions for "performance-based incentives" and "decoupling" stood as worded.

- Demand Side Management (DSM): Management tools and actions that are designed to result in decreases or shifts in customer energy demand and/or consumption.
- True-Up: A decoupling mechanism where a periodic adjustment in electric rates is used to correct for disparities between a utility's actual fixed-cost recovery and its authorized fixed-cost recovery.

NATURE & EXTENT OF FINANCIAL DISINCENTIVES

Hayman distributed questions raised in conversations with participants and grouped into categories (Appendix 5). These questions could be revisited after today's discussions to see which had been answered and which remained. Some could also be assigned for analysis, if appropriate. She also shared a flowchart she had drawn on the whiteboard and asked if there was any dissension about the process. Workshop participants accepted the flowchart.



Fixed-Cost Revenue Loss Analyses

Prior to the workshop, Lynn Anderson, IPUC, had e-mailed participants a memo and Excel worksheet (Appendix 6). He had calculated IPC's fixed-cost revenue losses under three 9-year scenarios that he had developed to try to quantify the nature and extent of financial disincentives. These calculations are gross estimates that are not adjusted for taxes, cost changes, offsetting benefits, etc. They also assume no intervening rate cases, which would reset the base rates upon which the fixed-cost revenue loss would be calculated on a going forward basis.~~to zero~~. He shared that information with the whole group and answered questions.

Integrated Resource Plan Scenario

- Under the IRP scenario, the fixed-cost revenue loss grows to about $1.3 million per year by 2013.
- The 9-year total for all rate classes is about $6 million, with a net present value of about $4 million. The residential 9-year total is about $2 million. These figures are based solely on energy charges, not energy and demand charges. Adding fixed-cost revenue loss from demand savings would increase the $6 million by about a third.

- Northwest Energy Efficiency Alliance (NEEA) efforts were excluded from the scenario.

Northwest Power and Conservation Council Scenario

- Under the NWPCC scenario, the fixed-cost revenue loss grows to about $23 million per year by 2013. The 9-year total for all rate classes is about $114 million, with a net present value of about $75 million. The residential 9-year total is about $51 million.
- Results from this analysis are consistent with numbers that Ralph Cavanagh came up with. His calculations show $45 million in fixed-cost revenue loss over the first five years, his number includes demand charge losses as well as energy charge losses. Anderson arrived at $38 million using only energy charge losses.
- For the commercial class, the loss/MWh unsold jumped from $9.70 under the IRP scenario to $41.50 under the NWPCC scenario. This class included both schedule 07 and 09 rate classes though. If the analysis were fine-tuned, this discrepancy would need to be addressed.
- IPC's share of 6.5% is based on sales. The potential is greater since IPC hasn't done much DSM in the last several years.
- How rate cases would affect the $114 million was uncertain. Intervening rate cases reset fixed-cost revenue requirements but do not allow IPC to recover revenue losses incurred since the previous rate case. Ric Gale said that an analysis of what would happen would be fairly simple to do.

Historical Residential Scenario

- Under this scenario, only residential fixed-cost revenue losses are calculated. Using weather-normalized kWh per customer consumption data, the hypothetical fixed-cost revenue loss grows to $18 million in 2003, the 9th year following IPC's 1994 rate case.
- The $18 million shown for 2003 is almost identical to what the IPUC will give IPC for the rate increase for residential customers under the just-completed rate case, despite the scenario being an oversimplification.
- Average monthly per customer usage decreased by 143 kWh in the 9-year period. During this time, IPC had very little residential DSM; its participation in NEEA probably accounts for less that 5% of the reduction. The reductions are mostly focused into two years (2001 and 2002) when there was also a nationwide reduction in electricity consumption. There were also 40% PCA increases in those two years. These electricity savings may have been offset by increased gas consumption.

Summary—Areas of Agreement

After the three scenarios were presented and discussed, participants listed their conclusions about the magnitude of the problem and the location of disincentives. Below are issues that were raised during this discussion:

- IPC's historical lost revenues are a disincentive to something, but it's difficult to say that they are a disincentive to energy efficiency since the lost revenues in the third scenario are not associated with DSM.
- If there is a relatively aggressive DSM program and it achieves energy-efficiency objectives, there is a cost to the company. What remains unknown is how much it would cost to "fix" the problem and whether that price is tolerable. In addition, it is important to understand what IPC would do differently if the company recovered costs incurred through DSM.
- "Demand reduction" occurs with higher pricing. But higher pricing isn't the solution that people are looking for. They would like to know how to separate demand reduction due to energy-efficiency programs from that due to higher prices. Also, what are the impacts of different energy-efficiency programs?

"STRAWMAN" PROPOSAL FOR AN IDAHO POWER TRUE-UP MECHANISM

Ralph Cavanagh introduced a strawman proposal for a true-up mechanism (Appendix 8). A true-up mechanism is "not about paying the company anything; it simply provides IPC a means for recovering fixed costs." It is designed around an authorized fixed-cost revenue requirement.

Under his proposal, the starting point would be the fixed-cost revenue requirement and retail rates approved by the IPUC in the latest IPC rate case. If, after the first year, changes in retail electricity use lead to under- or overrecovery of the fixed-cost revenue requirement, then a rate true-up would occur in the following year on the same schedule as IPC's current PCA. Until reestablished in the next IPC rate case, the currently approved fixed-cost revenue requirement would be automatically adjusted annually to reflect the same rate of increase or decrease shown for retail electricity sales, net of any DSM programs, in IPC's latest IRP. True-ups would occur annually based on any divergence between the total fixed-cost revenue recovery that forecast sales would have delivered and the fixed-cost revenues actually recovered. The true-ups would be done for each customer class based on divergence between actual and forecast sales to each customer class. IPC would continue to absorb the risk or benefits of purely weather-related effects on fixed-cost revenue recovery, as it does now. Actual sales would be weather normalized before the annual true-up calculation was made. Cavanagh emphasized that the maximum annual anticipated rate impact of the true-up mechanism, up or down, under extreme conditions would be 1.5%.

Several issues were raised during the presentation and associated discussion (Appendix 9):

- This mechanism does not include figuring out how much of the difference is attributable to different factors.
- Because the fixed-cost revenue requirement would track forecasted sales rather than historical sales, IPC would not be paying extra if DSM programs were successful. Every year, the company would be truing up to a number known in advance at the same schedule that is now used.
- Although Cavanagh proposed truing up for every customer class (except special contracts because of other complexities), the mechanism would work in part (for certain customer classes).
- At one point, IPC classified DSM as a supply side investment: the money was capitalized and amortized over a number of years. But the benefits didn't materialize for a number of reasons.
- Basing the true-up mechanism on forecasted sales might motivate IPC to inflate its forecasted numbers. Deterrents might include having the forecast adopted independently or using a different index after the next general rate case.
- To better understand the effects of DSM on fixed-cost revenue loss, people suggested rerunning the scenarios and running the Aurora model, given some of the discussion points raised during the workshop. The following action items resulted from this discussion and were assigned to Randy Lobb, Ric Gale, and Ralph Cavanagh to coordinate:
  - Rerun the IRP scenario with rate impacts by class
  - Rerun the NWPCC scenario with rate impacts by class
  - Use Aurora to estimate changes in power supply costs that may result from increased levels of energy ~~savings from~~ conservation
  - Recalculate scenario numbers with an interim rate case (assigned to Lynn Anderson)
- A poll of customers' appetite for energy-efficiency programs might help in estimating potential savings from conservation. David Hawk and Ric Gale will discuss the value and development of a poll.

NEXT STEPS/WRAP-UP

Hayman reviewed action items that need to be done before the next workshop. This workshop was set for November 8, 2004, from 9:30am - 3:30pm at IPC. The morning will be spent reviewing results of the model runs and Anderson's scenarios with an interim rate case included. The afternoon will be reserved for discussing performance-based incentives. Gale encouraged people to develop other strawmen if they have ideas. Cavanagh offered to circulate a proposal for a performance-based mechanism in advance of the workshop.

During a quick workshop evaluation, participants asked that people who will be sharing information distribute that information in advance so that people have a chance to review it.

APPENDIX 1—PARTICIPANTS

Name and Affiliation	E-mail Address	Phone No.
Peter Richardson, Industrial Customers of Idaho	peter@richardsonandoleary.com	938-7901
Don Reading, Ben Johnson Associates	dreading@mudspring.com	342-1700
Mike Youngblood, Idaho Power	myoungblood@idahopower.com	388-2882
Maggie Brilz, Idaho Power	mbrilz@idahopower.com	388-2848
Greg Said, IPC	gsaid@idahopower.com	388-2288
Lynn Anderson, IPUC	landers@puc.state.id.us	334-0353
Brad Purdy, Self	bmpurdy@hotmail.com	384-1299
Randy Lobb, IPUC	rlobb@puc.state.id.us	334-0350
Bart Kline, Idaho Power	bkline@idahopower.com	388-2682
Ralph Cavanagh, Natural Resources Defense Council	rcavanagh@nrdc.org	(415) 875-6100
Darlene Nemnich, Idaho Power	dnemnich@idahopower.com	388-~~2805~~2505
Tim Tatum, Idaho Power	ttatum@idahopower.com	388-5515
Laura Nelson, IPUC	lnelson@puc.state.id.us	334-0363
Scott Woodbury, IPUC	swoodbu@puc.state.id.us	334-0320
David Schunke, IPUC	dschunk@puc.state.id.us	334-0355
Bill Eddie, Advocates for the West	billeddie@rmci.net	342-7024 x 3
Ric Gale, Idaho Power	rgale@idahopower.com	388-2887
Terri Carlock, IPUC	tcarloc@puc.state.id.us	334-0356
David Hawk, J.R. Simplot Co.	david.hawk@simplot.com	389-7306

APPENDIX 2—AGENDA

ASSESSING FINANCIAL DISINCENTIVES AND RESOLUTION OPPORTUNITIES WORKSHOP #2

September 27, 2004
9:30am-12:30pm
Auditorium East
Idaho Power Corporate Headquarters
Boise, Idaho

Objectives:

1) Develop operational protocols, objectives and outcomes for this effort;
2) Continue investigating the nature and extent of financial disincentives to energy conservation programs (DSM);
3) Explore a potential decoupling mechanism to address financial disincentives.

Draft Agenda

Time	Topic	Process
9:00am	*Coffee/Tea available in meeting room*	
9:30am	**Welcome/Introductions/Meeting Overview** – Susan Hayman, Facilitator	Information
9:40am	**Workshop Operational Issues** – Susan Hayman • Workshop series purpose and products (incl. terminology) • Participant roles & responsibilities • Decision-making • Documentation	Information/Discussion
10:20am	**Nature & Extent of Financial Disincentives** • Fixed-Cost Revenue Loss Analyses – Lynn Anderson – Important Omissions, Caveats and Disclaimers – DSM-caused losses under IRP projection – DSM-caused losses under NWPCC draft DSM projection – Residential historical declining kWh per customer • Areas of agreement on the current situation	Presentation Discussion
11:20am	**BREAK**	
11:30am	**"Strawman" Proposal for an Idaho Power True-Up Mechanism** – Ralph Cavanagh	Presentation Discussion
12:10pm	**Wrap-Up** – Susan Hayman • Workshop schedule • Agenda items for next workshop – Susan Hayman • Evaluation	Discussion
12:30pm	**Adjourn**	

APPENDIX 3—OPERATIONAL PROTOCOLS

Workshop Series – Operational Protocol

Workshop Name: Assessing Financial Disincentives and Resolution Opportunities

Workshop Purpose:

1) To investigate the nature and extent of financial disincentives to investment in energy efficiency by Idaho Power Company and customers;
2) To investigate decoupling and performance-based ratemaking (incentives) as mechanisms to address financial disincentives (IPUC Order # 29558, 8/10/2004). *Other mechanisms can be subsequently explored if the participants agree that this would be useful.*

Workshop Products: A written report to the Idaho Public Utilities Commission to update the Commission on the status of the investigative workshops. This report will include a summarized assessment of:

1) The nature and extent of financial disincentives to investment in energy efficiency by Idaho Power Company;
2) Recommendations regarding specific decoupling and/or performance-based mechanisms that may reduce/remove these financial disincentives.
3) Recommendations for next steps.

Workshop Tenure: August 24 through December 15, 2004

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1) **Composition of Workshop Participants**

While workshops will be open to the public, it is expected that participants will generally represent the Idaho Public Utilities Commission, Idaho Power Company, Northwest Energy Coalition, representatives of industrial customers, representatives of residential customers, and representatives of irrigation customers.

2) **Roles & Responsibilities of Workshop Participants**

a) Be active in the discussion, be solutions-oriented, and act in "good-faith."
b) Help others at the table to understand your interests, and actively seek to understand the interests of others.
c) Be informed – Review the previous workshop summary, the agenda and prework in advance of the next workshop.
d) Follow-through in a timely manner with any assigned action items.
e) Attend workshops regularly – the group will not revisit decisions/discussions missed by others.
f) **Workshop Coordinators:** One representative each from Idaho Power Company (Mike Youngblood), Idaho Public Utility Commission (Lynn Anderson), ~~and~~ Northwest Energy Coalition (Bill Eddie), and industrial customers (Peter Richardson). Responsibilities include coordination with the facilitator on the workshop objectives, outcomes, agenda and process.

3) **Role & Responsibilities of the Facilitator**

a) Manage the workshops, serve as a process coach, maintain neutrality and impartiality, and reinforce the collaborative process.
b) Refine the objectives and outcomes for each workshop, in cooperation with the workshop coordinators. Propose a workshop agenda and appropriate processes to reach the identified

Page 1 of 1 – Operational Protocol

objectives and outcomes, and finalize this with the coordinators. The agenda, and any prework materials, will be distributed to participants at least one week prior to each workshop.

c) Communicate with participants outside of workshops as needed.

d) Maintain a record of workshop participants, and a summary of workshop discussions (see #6, Record Keeping).

e) Assist in preparation/compilation of the written report to the Idaho Public Utilities Commission.

4) **Analysis**

~~*Who is going to provide analysis support for this workshop (collect data, develop and analyze scenarios, etc.)?*~~ Analysis needs will be identified and assigned as they emerge.

5) **Decision-Making**

a) **Entities with multiple representatives:** While each individual participant will have input into the workshop deliberations, it is desirable that each entity represented speak with one voice in decision-making. Therefore, while numerous individuals may represent a given entity at a workshop, it is expected that one person will speak on behalf of the entity when decisions are made. Each entity should designate that person in advance. The facilitator will provide time for representatives to consult with each other as needed prior to critical decisions.

b) **Types of decisions:** There are two types of decisions participants will make:

- *Workshop decisions:* These decisions are related to workshop topics, process and schedule. Workshop decisions already made by the IPUC in Orders 29505 and 29558 will be honored. Decisions at the discretion of the group will be made by consensus.
- *Product decisions:* These decisions are related to the findings and recommendations workshop participants will present in their written report to the IPUC on December 15, 2004. Consensus will be the goal – However, if consensus cannot be reached, areas of agreement and disagreement on the findings and recommendations will be provided in the written report.

6) **Record-Keeping**

a) The facilitator will arrange for notes to be taken on a laptop computer during the workshop. The distributed workshop will include key discussion points, decisions, areas of agreement and disagreement, action items, etc. They will not be a transcription of "who said what."

b) The facilitator will be responsible for preparing the workshop summary and distributing it to participants within three business days after each workshop.

c) The facilitator will maintain a file of all workshop summaries, handouts, and products.

7) **Principles of Meeting Conduct**

a) Focus attention on the speaker (no side conversations)

b) Be specific, but succinct, in questions and comments

c) Participate fully, but don't dominate the discussion.

d) Respect other's contributions, and learn from them.

e) Challenge ideas, not people

f) Be on time

g) Turn cell phones, pagers or other electronic devices off or inaudible during meetings.

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APPENDIX 4—DEFINITIONS (WITH REVISIONS)

Definitions

Demand Side Management (DSM): Management tools and actions that are designed to result in decreases or shifts in customer energy demand and/or consumption~~Anything that a utility does that affects customer energy demand, consumption and/or time of use~~.

Performance-Based Incentives (PBI): Mechanisms that allow a utility to share and retain benefits gained from energy efficiencies, as well as provide consequences for failing to meet efficiency goals.

Decoupling: Severing the link between a utility's kWh sales and its recovery of revenues to cover fixed costs.

True-Up: A decoupling mechanism where a periodic adjustment in electric rates is used to correct for disparities between a utility's actual fixed cost ~~recoveries~~recovery~~,~~ and its authorized fixed-cost recovery~~rate of return~~.

Appendix 5—Questions Raised in Participant Conversations

Questions Raised in Participant Conversations

Financial Disincentives

- What effects do disincentives have on customers and on IPC?
- What is the projected loss of revenue to IPCO from DSM programs over the next 10years?
- What are the NWPC projections of demand over the next 10 years (relevant to IPCO)?
- What would the removal of disincentives accomplish for customers and IPCO?
- Should IPCO be "made whole" when they encourage customers to use less of their products (and what does it mean to be "made whole")?
- What should be the basis for reimbursement of lost kWh and out-of-pocket cost to support DSM?
- If disincentives were not in place, could IPCO invest more in DSM?
- Are there disincentives to DSM other than financial?

DSM Programs

- What effect does DSM have on resource acquisition?
- If customers ultimately have to pay more (to decouple fixed costs from variable energy use), what DSM programs will be created?
- Should there be consequences for not investing in DSM?
- If funds are invested to support DSM programs…

  -- How will these funds be administered?

  -- How will the efficacy of administration be measured/monitored?

Questions Raised in Participant Conversations (cont'd)

Decoupling and/or Performance-Based Mechanisms

- What effects would decoupling have on customers and on IPCO?
- If decoupling would have been in place during the last 10 years, what would have been the effect on customers and IPCO (state assumptions)
- If decoupling were adopted at IPCO, what would be the options for structuring (rate classes, class-specific or system-wide, apply to energy charges or both energy and demand charges, etc.)
- What are the side effects to decoupling?
- What effects would performance based mechanisms have on customers and on IPCO?
- What are the side effects to performance-based incentives?
- What criteria will we use to evaluate decoupling and performance-based mechanisms?

Other Mechanisms

- Are there more appropriate mechanisms than decoupling and/or performance-based mechanisms to address IPCO financial disincentives?

APPENDIX 6—FIXED-COST REVENUE LOSS ANALYSES

IPC DSM F-C Revenue Loss - IRP

Only DSM Selected in the 2004 IRP *(2004-2013 Planning Period)*
Idaho Power IPC-E-04-018, IRP Technical Appendix
Energy Savings (Excluding NEEA)
Net of Free Riders, Includes Losses
Energy Savings (Megawatt-hours)

	Year	Residential	Commercial	Irrigation	Industrial	Total MWh
	2005	1,070	389	5,767	9,427	16,653
	2006	2,625	1,087	11,534	18,853	34,100
	2007	4,193	1,900	17,300	28,280	51,674
	2008	5,784	2,810	23,067	37,706	69,367
	2009	7,397	3,801	28,834	47,133	87,166
	2010	9,205	4,861	34,601	56,559	105,226
	2011	11,028	5,980	40,368	65,986	123,363
	2012	12,872	7,149	46,134	75,412	141,566
End of IRP Planning Period	2013	14,734	8,359	51,901	84,839	159,833
					aMW (2004 IRP)=	18.25
	Total	68,908	36,337	259,506	424,195	788,946

(Numbers by IPC 9/21/04)
Peak Reduction (MW)

Res.	Com.	Irrig.	Ind.	Total
0.6	0.1	2.9	1.2	4.9
1.5	0.4	5.8	2.4	10.1
2.5	0.7	8.7	3.6	15.4
3.4	1.1	11.5	4.8	20.8
4.3	1.5	14.4	6.0	26.2
5.3	1.9	17.3	7.2	31.7
6.3	2.4	20.2	8.4	37.2
7.3	2.8	23.1	9.6	42.8
8.3	3.3	26.0	10.8	48.3
8.3	3.3	26.0	10.8	48.3
Peak MW (Energy Programs)				48.3
Peak MW (Demand Response)				75.6
Total Peak MW Selected DSM				123.9

Calculation of Fixed Cost Lost Revenue per MWh for Various Rate Schedules

	Residential	Commercial*	Irrigation	Industrial**
Energy Rate ($/MWh)	51.9	30.0	32.6	21.8
Variable Cost ($/MWh)	20.7	20.3	23.5	18.5
Loss/MWh unsold	**$31.20**	**$9.70**	**$9.10**	**$3.30**

(*) Commercial rate is a weighted avg. of schedules 07 & 09S based on energy use.
(**) Ind. rate is a wghtd. avg. of schs. 09 P & T and 19 S, P & T based on energy use.

Note that the $/MWH here are diff. for com. & indust. than on NWPCC sheet

Fixed Costs Not Recovered Due to DSM Selected in IRP

	Year	Residential	Commercial	Irrigation	Industrial	Total
	2005	$33,370	$3,775	$52,480	$31,109	$120,734
	2006	81,905	10,548	104,959	62,215	259,627
	2007	130,837	18,432	157,430	93,324	400,023
	2008	180,467	27,256	209,910	124,430	542,063
	2009	230,799	36,871	262,389	155,539	685,599
	2010	287,187	47,156	314,869	186,645	835,857
	2011	344,084	58,008	367,349	217,754	987,194
	2012	401,601	69,341	419,819	248,860	1,139,621
End of IRP Planning Period	2013	459,689	81,082	472,299	279,969	1,293,038
	Total	$2,149,939	$352,469	$2,361,505	$1,399,844	$6,263,756
WACC = 7.20%						
PV 9-yr. (2005-2013)		$1,434,141	$ 232,128	$1,593,395	$ 944,526	$ 4,204,190
Avg Annual		429,988	70,494	472,301	279,969	1,252,751
Levelized (9-yr.)		214,415	34,705	238,224	141,214	628,557

The fixed-costs not recoverd at left are the product of multiplying each year's energy savings (excluding NEEA) in the top box by the loss/MWh unsold in the middle box (IPC adj. of Eric Hirst numbers). The "losses" are not adjusted for income taxes, cost changes, offsetting benefits, etc. All losses assume no rate cases 2005-2013.

IPC DSM F-C Revenue Loss - NWPCC

NWPCC Draft 5th Plan -- Not Reviewed By Council
Achievable, Cost-Effective DSM Potential by 2025

Sector	Item	%	Potential DSM in NW 2005-2025 Total aMW	IPC's 20-yr. aMW @ 6.50%	IPC's annual aMW	IPC's annual MWh	2005	2006	2007	2008	2009	2010	2011	2012	2013	Total 9-year F-C Rev. Loss
							Idaho Power's Fixed-Cost Revenue Losses ($millions)									
Res.	Refrigerators		5													
Res.	Clothes Washers		135													
Res.	Dishwashers		10													
Res.	Water Heaters		80													
Res.	H.P. Water Heaters		195													
Res.	H.W. Heat Recovery		20													
Res.	Compact Flourescent		535													
Res.	New Space Cond.		40													
Res.	Existing Space Cond.		95													
Res.	HVAC Upgrades		65													
Res.	HVAC Conversion		70													
Res.	HVAC Commission		20													
	Res. Total	44.8%	1,270	82.6	4.13	36,157	1.1	2.3	3.4	4.5	5.6	6.8	7.9	9.0	10.2	$50.8
Com.	Equipment, new/repl.		85													
Com.	HVAC, new/repl.		150													
Com.	Infrastructure, new/repl.		20													
Com.	Lighting, new/repl.		245													
Com.	Shell, new/repl.		15													
Com.	Equipment, retrofit		110													
Com.	HVAC, retrofit		120													
Com.	Infrastructure, retrofit		110													
Com.	Lighting, retrofit		115													
Com.	Shell, retrofit		10													
	AC/DC power conv.		155													
	Com. Total	40.0%	1,135	73.8	3.69	32,313	1.3	2.7	4.0	5.4	6.7	8.0	9.4	10.7	12.1	$60.3
Irrig.	All Agriculture		80													
	Irrig. Total	2.8%	80	5.2	0.26	2,278	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.2	0.2	$0.9
Ind.	All Non-Aluminum		350													
	Ind. Total	12.3%	350	22.8	1.14	9,965	0.0	0.1	0.1	0.2	0.2	0.3	0.3	0.4	0.4	$2.2
	Total	100.0%	2,835	184.3	9.21	80,712	2.5	5.1	7.6	10.2	12.7	15.2	17.8	20.3	22.8	$114.2

	2005	2006	2007	2008	2009	2010	2011	2012	2013
Cumulative Total	$2.5	$7.6	$15.2	$25.4	$38.1	$53.3	$71.1	$91.4	$114.2

$/MWh From IPC's 3/30/04 Eric Hirst Decoupling Report, p. 5 -- IPC Updated

	Res.	Com. -7	Irrig.	Indust.	-all 9 & 19 sch. (wt. avg.)
Energy Charge	51.90	62.60	32.60	24.40	Note that the $/MWH here
Variable Cost	20.70	21.10	23.50	19.50	are diff. for com. & indust.
Loss/MWh unsold	$31.20	$41.50	$9.10	$4.90	than on IRP-selected sheet.

Idaho Power's 6.5% share is based on its current NEEA allocation, which may not represent its potential for each program or customer class.

All revenue losses assume no intervening rate cases and no customer growth.

Idaho Power-Idaho Only Sales and Customers

IPC DSM F-C Revenue Loss - Historical

Residential Only

Year	Residential Revenue	Weather Normalized MWh Sold	Customers	Weather Norm. kWh Cust./mo.	Hypothetical Fixed-Cost Revenue Loss
1987	$129,436,545		217,104		
1988	140,569,164		219,005		
1989	155,211,941		221,617		
1990	153,080,652		226,323		
1991	162,388,156		231,347		
1992	158,306,311		237,837		
1993	173,124,151	3,524,040	246,278	1,192	
1994	174,880,654	3,589,867	255,735	1170	
1995	184,321,208	3,717,787	264,901	1170	23,324
1996	191,716,079	3,776,360	273,834	1,149	2,108,207
1997	190,655,639	3,864,922	282,054	1,142	2,945,197
1998	201,626,186	3,987,589	290,532	1,144	2,831,082
1999	203,972,260	4,076,279	300,072	1,132	4,242,165
2000	215,560,768	4,160,997	309,499	1,120	5,727,683
2001	250,774,139	4,142,665	318,076	1,085	10,056,112
2002	296,274,337	4,100,268	326,788	1,046	15,194,468
2003	266,499,664	4,141,393	336,204	1,027	18,035,272
				9-year total=	$61,163,509

Post 1994 "Hypothetical Fixed-Cost Revenue Loss" calculation uses 1,170 kWh per month as the residential weather normalized consumption base.

The average consumption decrease of 143 kWh from 1,170 in 1994 to 1,027 in 2003 represents a 1.4% average annual decrease. Idaho Power had very little residential DSM during this time period. It is likely that increased natural gas penetration is responsible for most of the decreased electricity use.

The calculation uses $31.20 as the residential "loss/MWh unsold" (IPC's update to Hirst's number) and assumes the fixed-cost lost revenue recovery formula would have compensated IPC for all weather normalized declining kWh sales per customer.

Total Retail Sales, All Classes

	Revenue	MWh	Customers
1994	434,690,290	11,622,194	306,881
1995	438,527,438	11,395,255	317,760
1996	458,675,200	12,410,881	328,676
1997	454,141,771	12,594,311	339,022
1998	488,226,974	12,720,471	349,339
1999	489,565,724	13,077,842	360,021
2000	537,735,312	13,895,478	370,101
2001	624,448,755	12,391,914	380,593

$/MWh From IPC's 3/30/04 Eric Hirst Decoupling Report, p. 5 -- IPC Updated

	Res.	Com. -7	Irrig.	Indust. -all 9 & 19 sch. (wt. avg.)	
Energy Charge	51.90	62.60	32.60	24.40	Note that the $/MWH here
Variable Cost	20.70	21.10	23.50	19.50	are diff. for com. & indust.
Loss/MWh unsold	$31.20	$41.50	$9.10	$4.90	than on IRP-selected sheet.

Year	1-yr. Avg. Bill	Revenue per kWh	Actual Kwh sold	Actual 1-yr. Avg. kWh/cust. per month	Actual 3-yr. Avg. kWh/cust. per month	Weather Norm. kWh Sold
1987	49.68	0.0432	2,995,218,168	1,150		
1988	53.49	0.0446	3,148,903,043	1,198		
1989	58.36	0.0469	3,306,433,702	1,243	1,197	
1990	56.37	0.0474	3,230,831,759	1,190	1,210	
1991	58.49	0.0473	3,430,432,527	1,236	1,223	
1992	55.47	0.0481	3,289,387,264	1,153	1,193	
1993	58.58	0.0483	3,582,828,720	1,212	1,200	3,524,040,421
1994	56.99	0.0484	3,610,314,912	1,176	1,180	3,589,867,417
			8-yr. Average, 1987 to 1994 =		**1,195**	
1995	57.98	0.0518	3,556,816,130	1,119	1,169	3,717,787,134
1996	58.34	0.0508	3,775,150,065	1,149	1,148	3,776,360,493
1997	56.33	0.0496	3,843,356,042	1,136	1,134	3,864,921,749
1998	57.83	0.0518	3,891,822,308	1,116	1,134	3,987,588,792
1999	56.65	0.0510	3,997,632,389	1,110	1,121	4,076,279,049
2000	58.04	0.0515	4,189,182,972	1,128	1,118	4,160,997,320
2001	65.70	0.0609	4,117,127,872	1,079	1,106	4,142,664,831
2002	75.55	0.0706	4,197,803,194	1,070	1,092	4,100,268,216
2003	66.06	0.0629	4,238,675,325	1,051	1,067	4,141,393,426

APPENDIX 7—FLIP CHARTS REGARDING ANALYSES

Financial Disincentives

(Lynn Anderson's Presentation)

1) Add in lost demand charge to calculating of total financial loss (IRP scenario)
2) $6 million loss in revenue under IRP DSM projections. IRP—no tax impact if company made whole
3) Lynn's projections do not include savings from NEEA.
4) $114 million loss in revenue under NWPCC scenario.

Financial Disincentives (cont.)

5) 6.5% kWh sold in NWPCC attributed to IPC
6) Intervening rate cases reset fixed-cost requirements, but do not allow IPCO to recover lost $$ since previous rate case.
7) (hist) NEEA effects < 5% customer use—has occurred without utility DSM programs.
8) Over 9-year period, utility had no active residential DSM program.

Conclusions—Financial Disincentives

1) IPCo historical lost revenues is a disincentive to something. Historically, not tied to DSM.
2) If there is a relatively aggressively DSM program, and achieves objectives, there is a cost to company.
3) "Demand destruction" occurs with higher pricing.
4) Lost revenues occur with successful DSM programs

   —is it a disincentive

APPENDIX 8—"STRAWMAN" PROPOSAL FOR AN IDAHO POWER TRUE-UP MECHANISM

"STRAWMAN" PROPOSAL FOR AN IDAHO POWER TRUE-UP MECHANISM

Submitted by Ralph Cavanagh, NRDC (9/22/04)

1. Starting point: fixed-cost revenue requirement and retail rates approved by Idaho PUC in latest Idaho Power rate case.

2. If, after initial year, changes in retail electricity use lead to under- or over-recovery of fixed cost revenue requirement, a rate true-up would occur in the following year on the same schedule as the Company's current Power Cost Adjustment.

3. Until reestablished in the next Idaho Power rate case, the currently approved fixed cost revenue requirement would be automatically adjusted annually to reflect the same rate of increase (or decrease) shown for retail electricity sales, net of any DSM programs, in Idaho Power's latest IRP. True ups would occur annually based on any divergence between the total fixed-cost revenue recovery that forecast sales would have delivered and the fixed-cost revenues actually recovered (so if, for example, sales were forecasted to increased by 2 percent and actually increased by a larger percentage, Idaho Power would refund the difference at the time of the next Power Cost Adjustment; if retail sales increased by a smaller percentage than forecast, Idaho Power would get back the lost revenues at the time of the next Power Cost Adjustment).

4. True-ups would occur by customer class based on divergence between actual and forecast sales to each customer class.

5. Idaho Power would continue to absorb the risk or benefits of purely weather-related effects on fixed-cost revenue recovery, as it does now. This would mean weather normalizing actual sales before making the annual true-up calculation.

MAXIMUM ANNUAL ANTICIPATED RATE IMPACT OF THE TRUE UP MECHANISM, UP OR DOWN, UNDER EXTREME CONDITIONS = 1.5 PERCENT.

APPENDIX 9—FLIP CHARTS REGARDING STRAWMAN PROPOSAL

Strawman Proposal

1) True-up by each customer class
2) Mechanism could be applied to individual/selected classes and still be acceptable*
3) Remove special contracts from mechanism.
4) *Plea to not exclude industrial class
5) Predicted load growth in each class to establish authorized revenue requirement.

Strawman Proposal (cont.)

6) True-up would result in surcharges/benefits by rate class
7) Forecast of fixed-costs may, potentially, create an incentive to inflate the forecast in the future.
8) Because this rate case is already decided, fixed-cost projections would be established without consideration of true-up mechanism effect

   --May be a challenge in the future

   --May apply inflation factor in future

Assessing Financial Disincentives and Resolution Opportunities, Workshop #3

November 8, 2004, 9:30 a.m. to 3:30 p.m.
Auditorium East, Idaho Power Corporate Headquarters, Boise, ID

Facilitation	Susan Hayman, North Country Resources, Inc.
Documentation	Natalie Chavez, Chavez Writing & Editing, Inc.

Workshop Objectives

1) Continue investigating the nature and extent of financial disincentives to energy conservation programs; identify areas of agreement and any additional information needs.
2) Identify criteria that workshop participants would use to evaluate the applicability/desirability of potential mechanisms to address disincentives.[1]
3) Brainstorm potential mechanisms to address disincentives, including additional true-up mechanisms, performance-based incentives, etc.[1]

Workshop Decisions and Outcomes

The next meeting is scheduled for December 1, 9:30am to 3:30pm at IPC. An additional meeting is set for December 13. If people with action items are unable to complete them in time for the December 1 meeting to be productive, that meeting will be cancelled and all parties notified by Susan Hayman, facilitator.

Action Items

What?	Who?	When?
1) Check with Commission regarding scope of performance-based incentive discussion (is it DSM-related only?) and provide response to the workshop participants	Randy	ASAP
2) Talk with Bill Eddie about report coordination; reply to Hayman	Nancy	November 9
3) E-mail proposed report coordination assignments to the workshop participants	Susan	In next few days
4) Coordinate timing of status report	Susan	Next meeting or e-mail
5) Develop PBR strawman suitable for Idaho and successfully demonstrated elsewhere	IPUC	Next meeting
6) Refine true-up mechanism	Ralph	Next meeting
7) Analyze the refined true-up strawman and PBR strawman	IPC	Deferred

[1] With the approval of workshop participants, Workshop Objectives 2 and 3 were deferred to the December 1 workshop to allow for more extensive presentation and discussion of financial disincentives information at this workshop.

WORKSHOP INTRODUCTION

Susan Hayman, North Country Resources, welcomed participants (Appendix 1), had them introduce themselves, and then reviewed the agenda (Appendix 2). She distributed revised copies of the operational protocols (Appendix 3) and reviewed posters showing purpose, products, definitions, and principles of meeting conduct (Appendix 4). Although three key participants representing the NWEC perspective were absent[2], the group decided to listen to planned presentations, discuss the information, and represent the NWEC perspectives as best they could, but not draw any conclusions until the others were present.

CONTINUED EXPLORATION OF FINANCIAL DISINCENTIVES

Scenarios with Interim Rate Cases

Before the workshop, Lynn Anderson, IPUC e-mailed participants a memo and two Excel worksheets (Appendices 5 and 6). He had incorporated three interim rate cases to recalculate IPC's fixed-cost revenue losses under two of the three 9-year scenarios that he had presented at the September 27 workshop. Under both scenarios, forward-looking revenue losses from past DSM efforts are eliminated (except for an assumed six-month lag between the end of the rate case test year and rate implementation), even though past DSM savings are assumed to persist into the future. DSM efforts that occur after each rate case test year result in new fixed-cost revenue losses that accrue until the next rate case. As a surrogate for rate case adjustments, the levels of fixed-cost revenues per MWh are increased by the average MWh growth rate projected in the IRP for each rate class.

Anderson first showed results of his recalculations of the IRP level of DSM (which excludes NEEA). The IRP rate-case adjusted, 9-year total fixed-cost revenue loss is $3 million, or about half of the $6.2 million presented previously. The present value of the $3 million is about $2 million, and the levelized loss is $0.3 million per year.

Next, he showed results under IPC's 6.5% share of the NWPCC level of DSM (which includes NEEA, fuel conversions, building codes, appliance standards, and other DSM for which utilities have limited, little, or no control). The NWPCC rate-case adjusted, 9-year total fixed cost revenue loss is $54.6 million, compared with the $114.2 million presented previously. The present value of the $54.6 million is about $39 million, and the levelized loss is $6 million per year.

Prior to the meeting, Cavanagh e-mailed a response to Anderson's recalculations (Appendix 7). Copies were made and distributed to those who had not received the e-mail. First, Cavanagh reminded people that NWPCC projections were not the upper limits of energy efficiency targets. Second, he disagreed with Anderson's elimination of continued revenue losses after a rate case. According to Cavanagh, using this approach understates IPC's losses from persistent savings and rewards short-lived efficiency measures while discouraging durable savings.

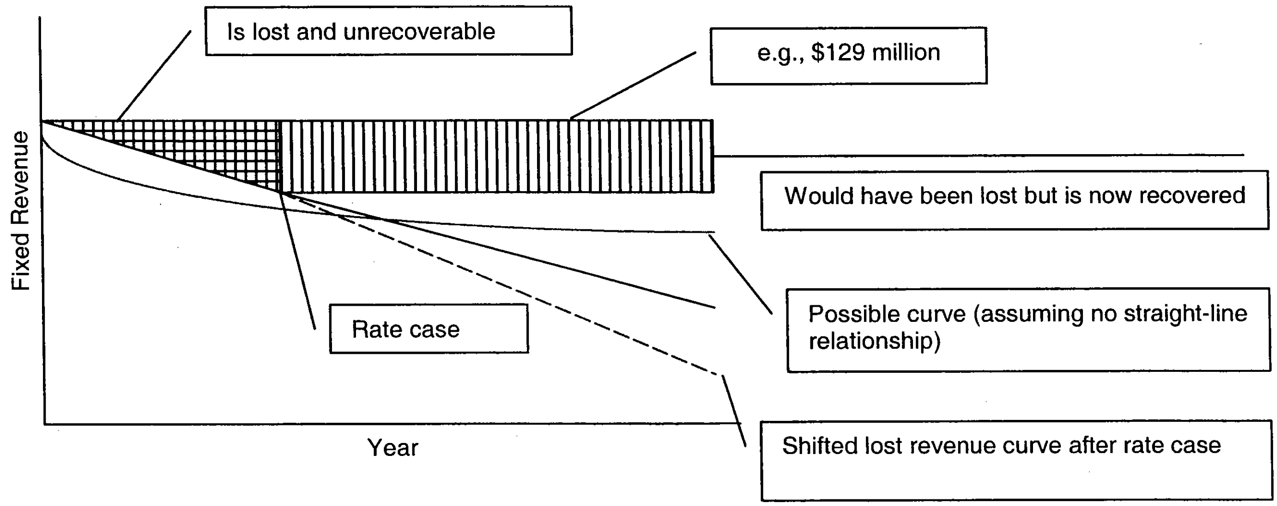
Following the presentation, participants raised and discussed the following issues:

- IPC loses fixed cost revenues when consumption declines. It is still uncertain how much reduced consumption is due specifically to DSM rather than to other factors. Therefore, some participants aren't certain whether this situation is best resolved by a true-up mechanism or some other disincentive/incentive mechanism.
- A decoupling/recoupling or true-up mechanism is not an incentive but a removal of a disincentive.
- More frequent rate cases would reduce fixed cost lost revenue even more than the hypothetical 3-year interval rate cases included in this analysis.
- Fixed cost revenues may be over-collected in the case where kWh sales, less DSM savings, are greater than the forecasted kWh growth, resulting in a refund for the customers under this true-up

[2] Ralph Cavanagh (Natural Resources Defense Council), Bill Eddie (Advocates for the West), and Nancy Hirsh (NW Energy Coalition) were absent at the beginning of the meeting. Their absence left no representatives of the NWEC stakeholder group. Hirsh arrived before lunch break, and Cavanagh participated via conference call in the afternoon. Eddie was unable to participate at all.

mechanism. At the same time, increased kWh sales will usually mean an increase in customer growth, which may require IPC to spend money for a new distribution plant and equipment. IPC is concerned about the possible scenario where they are giving a refund to customers at the same time as expending dollars in capital investment.

- What level of fixed costs, if recovered, would encourage or allow IPC to do what it wouldn't do otherwise with DSM or other programs?
- Greg Said, IPC, illustrated what happens between rate cases (see below) in the absence of a true-up mechanism. Lost fixed cost revenues from DSM could accumulate over a 10-year period unless a rate case adjusts the rates up to recover the lost fixed costs. This adjustment would change the angle of the lost revenue line down (in blue) so that future fixed cost losses are accelerated. For the sake of illustration, Said assumed a straight-line reduction, although it would likely be curved (in red). Anderson said that the surrogate for the blue dotted line was captured in his analysis.



Rate Impacts by Class under IRP and NWPCC Projections

Mike Youngblood, IPC, distributed a 10-page packet with rate impacts under the true-up mechanism for both IRP and NWPCC energy efficiency projections (Appendix 8) and a single sheet regarding fixed cost lost revenue per MWh by customer class (Appendix 9) prepared by Tim Tatum, IPC. Under this model, the true-up mechanism is based on forecasted sales as the method for IPC to recover fixed costs. Youngblood showed the assumptions he could change to analyze various scenarios.

Using the residential rate class, he walked participants through the model, which also included high- and low-growth scenarios to illustrate a range around the base case. The following issues were raised during the discussion (see Appendix 10 for flip chart notes):

- If energy sales grow faster than forecasted and DSM equals growth, there will be no apparent divergence from the base case.
- Although this model is not based on customer counts, increased kWh growth likely means increased customer growth. If so, IPC has to make capital investments for new customers. Youngblood commented that his numbers reflect divergence from an assumed 2% growth rate. Hypothetically, an increase in kWh use and an increase in the number of customers may result in a refund to customers <u>and</u> the requirement for IPC to add facility investment.
- For DSM, the percentage of class increase is still relatively small on an annual basis in the short term. Regular rate cases would adjust recovery so that the long-term effect wouldn't be as high as modeled.
- Trends of true-up are similar among rate classes.

Youngblood then presented a similar model of the true-up mechanism based on customer counts rather than forecasted sales. Youngblood did not provide this dynamic model as a handout but demonstrated it to the group. Appendix 11 includes one scenario based on certain input assumptions. For this analysis, he used weather-adjusted numbers, $30.14 as the total fixed cost per MWh, and 12,549 kWh to represent the average consumption for a residential user. The high and low scenarios represent 1% increase above and decrease below that average use per customer. Again, people could chose from among a number of assumptions to see their effects. Trends were similar to those under the forecasted sales true-up mechanism although magnitudes changed. The impact over a 20-year period, all else being equal, is a slight increase to rates, which is consistent with recovery of lost fixed revenues. Youngblood commented that the customer count mechanism works better with residential and small commercial customers, while the forecasted sales approach works better for industrial and irrigation customers.

Power Supply Costs under Increased Energy Conservation

Tim Tatum, IPC, distributed a four-page handout (Appendix 12) with results from the Aurora model conducted to analyze impacts of increasing levels of DSM on power supply costs. Mike Rufo of Quantum Consulting provided IPC an assessment of residential and commercial DSM potential within the Company's service territory by 2013. For the analysis, Portfolio 11 from the Company's 2004 IRP was modified to include Quantum Consulting's estimates of achievable DSM. The original Portfolio 11 was then used as the base case in the analysis. Tatum pointed out that Northwest Power and Conservation Council (NWPCC) estimates of achievable DSM are higher because they include market transformation, tax credits, and other mechanisms necessary to achieve those numbers. The IRP only accounts for direct acquisition program savings and does not include savings attributable to the Northwest Energy Efficiency Alliance (NEEA). When the 2004 IRP DSM resources are combined with Quantum Consulting's assessment findings and IPC's share of NEEA market transformation savings, the total is greater than NWPCC estimates of achievable DSM for IPC.

IPC decided to include the higher level of DSM (excluding NEEA) into a modified portfolio to allow them to analyze impacts to energy and capacity constraints (see Appendix 13 for flip chart notes). The first sheet of the handout (Appendix 12) shows the higher level of DSM, which allows IPC to defer resources (shown in orange blocks). The deferral of these resources results in an increase in variable supply costs due to decreased market sales potential. However, the fixed cost benefit of the deferral results in net savings. The second sheet shows the impact to power supply costs, excluding fixed costs. Factoring in DSM savings, power supply costs are reduced in all years except 2007, which is when the first Combined Heat and Power (CHP) resource is deferred. The third sheet shows portfolio fixed costs comparisons, with and without DSM fixed costs, between the base case and increased DSM portfolios. In the two years with CHP deferrals (2007 and 2010), there is a net decrease in fixed costs. The yellow columns show the costs to achieve DSM. Results showing the impacts of increasing levels of DSM on power supply costs are included on the last page. By increasing levels of DSM and organizing the portfolio for deferrals, the net present value between the two portfolios from now through 2033 is $36.3 million. This analysis indicates conservation has occurred and IPC will spend $36 million less in resources as a result. Extra costs would be incurred to the system for the first several years, and the break-even point would occur in 2022. The analysis showed that increased DSM could reduce power supply costs in the long run, but the disincentive needs to be removed early on.

Commission Report

The participants expressed concern that there is not enough time before the December 15 deadline given in the IPUC order to complete the investigation of the issues and draft a complete report. They decided to submit a status report instead, which IPUC staff said will be sufficient as long as it describes the group's progress and anticipated due date for the completed report. Responsibility for drafting the status report will be assigned at the next meeting.

Nancy Hirsh will talk with Bill Eddie about serving as report coordinator. Once written and compiled, drafts will be circulated to all participants, though suggested revisions from participants should be coordinated by each party (ICIP, IPC, IPUC, NWEC) before being sent back to the report coordinator. In the meantime, work group members brainstormed the following outline for the report:

I. **History**—events leading up to the order and the parties involved in the work group. The IPUC volunteered to write this section

II. **What the work group did**—issues raised, studies performed, mechanisms explored, assumptions made, and possible solutions detailed. The outline should allow means for showing the areas of agreement as well as areas of disagreement.

III. **Conclusions and recommendations**—conclusions drawn from the studies. This would reflect study information and perhaps respond to the four material questions discussed at this workshop (see Appendix 15).

IV. **Ancillary information**—figures, tables, study details, workshop summaries, and any other attachments needed to clarify or substantiate information.

After developing the draft outline (see Appendix 14 for flip chart notes), participants raised the need to include information about performance-based ratemaking (PBR) alternatives. The order had charged the work group with looking at alternatives to promoting DSM, one being decoupling and another being PBR. IPUC staff volunteered to develop a PBR strawman that is centered on DSM for the next meeting. If there is time to deliver the strawman to IPC for analysis before the December 1 meeting, the IPUC will do so. Otherwise, analysis will be conducted before the December 13 meeting.

QUESTIONS RAISED

The following questions were developed before or during the workshop and discussed once Cavanagh was able to participate via conference call (see Appendix 15 for flip chart notes):

- Are there financial disincentives to energy conservation?
- If there are financial disincentives, where are they (nature) and what is their extent?
- Is fixed cost recovery the issue/best way to address DSM?
- How much lost revenue (recovered) will cause the company to do something otherwise?
- What other information do we need?

Question 1—Existence of Financial Disincentives

All parties agreed that lost fixed cost revenue was associated with every kWh not sold.

Question 2—Nature and Extent of Financial Disincentives

Participants generally accepted the following conclusions:

- The nature and extent of the financial disincentive depends on the frequency of rate cases and the magnitude of IPC's energy efficiency program.
- The loss/fixed margin associated with every unsold kWh is needed to recover the fixed costs set in a rate case. However, over the last 10 years, IPC has implemented no DSM but experienced a huge loss/fixed margin.
- IPC could exert huge effort on programs that don't materialize. Nor would removal of disincentives guarantee energy conservation.

Question 3—Best Approach for Addressing DSM

Participants agreed that this question couldn't be answered yet since performance-based ratemaking alternatives haven't been explored.

Question 4—Amount of Lost Revenue Recovery to Effect Change

While striving to answer this question, the following issues were raised:

- Ric Gale, IPC, talked about IPC's commitment to re-energize DSM programs from a good faith stance. But out-of-pocket expenses for DSM (the immediate need) are a bigger concern than lost revenue recovery at this time. If a mechanism for eliminating the financial disincentive could be implemented cleanly, the company would want to pursue it. In the meantime, IPC has made significant strides in DSM proposals and savings that can be achieved without lost revenue recovery.

- One the other hand, management does ask Darlene Nemnich, IPC, about lost revenues any time she takes a DSM program to management for funding. Lost revenues are an issue at the programmatic implementation level.
- The IPUC is concerned about allowing the company to collect fixed costs that may not be associated with DSM efforts.
- IPC may not be as concerned about lost revenues given the amount of DSM projected in the IRP, which is less than half the NWPCC's target.
- Although fuel costs, which are given to IPC as fuel recovery, can be volatile and can affect the company as adversely as lost fixed cost revenue, the approach does differ.

Question 5—Information Needs

The analyses presented today addressed some of the questions that people had. However, the need still exists for a way of determining the amount of savings resulting from DSM. In the future, monitoring and evaluation results of DSM programs may contribute to understanding the amount of fixed costs associated with DSM. Because a true-up mechanism may address some but not all concerns, participants want to see similar analyses of PBR alternatives. IPUC volunteered to develop a PBR strawman for the next meeting.

NEXT STEPS/WRAP-UP

Hayman reviewed action items to be completed before the next workshop (Appendix 16). This workshop is scheduled for December 1, 2004, from 9:30am to 3:30pm at IPC. During this meeting, participants will hear strawman presentations, discuss evaluation criteria, and develop the status report for the Commissioners. If people with action items are unable to complete them for the meeting, Hayman will notify participants that the meeting will be postponed until December 13.

APPENDIX 1—PARTICIPANTS (shading indicates work group participants unable to participate in person or by phone in workshop #3)

Name and Affiliation	Name and Affiliation
Lynn Anderson, IPUC	Laura Nelson, IPUC
Maggie Brilz, Idaho Power	Darlene Nemnich, Idaho Power
Terri Carlock, IPUC	Molly O'Leary, Industrial Customers of Idaho (sitting in for Peter Richardson)
Ralph Cavanagh, Natural Resources Defense Council	Brad Purdy, Community Action Partnership Association of Idaho
Bill Eddie, Advocates for the West	Don Reading, Ben Johnson Associates
Ric Gale, Idaho Power	Greg Said, IPC
David Hawk, J.R. Simplot Co.	David Schunke, IPUC
Nancy Hirsh, NW Energy Coalition	Tim Tatum, Idaho Power
Bart Kline, Idaho Power	Mike Youngblood, Idaho Power
Randy Lobb, IPUC	Scott Woodbury, IPUC

APPENDIX 2—AGENDA

ASSESSING FINANCIAL DISINCENTIVES AND RESOLUTION OPPORTUNITIES WORKSHOP #3

November 8, 2004
9:30am-3:30pm
Auditorium East
Idaho Power Corporate Headquarters
Boise, Idaho

Objectives:

1) Continue investigating the nature and extent of financial disincentives to energy conservation programs; identify areas of agreement and any additional information needs.
2) Identify criteria that workshop participants would use to evaluate the applicability/desirability of potential mechanisms to address disincentives. ***Deferred***
3) Brainstorm potential mechanisms to address disincentives, including additional true-up mechanisms, performance-based incentives, etc. ***Deferred***

Final Agenda

Time	Topic	Process
9:15am	*Coffee/Tea available in meeting room*	
9:30am	**Welcome/Introductions/Meeting Overview** – Susan Hayman, Facilitator	Information
9:45am (We will take a morning break when it is most convenient to the group)	**Continued Exploration of Financial Disincentives** • Action item reports: ➢ IRP, NWPCC and historical residential scenarios calculated with an interim rate case (but without a true-up mechanism) – Lynn Anderson ➢ Rate impacts by class under IRP and NWPCC projections – Mike Youngblood ➢ Potential changes in power supply costs from increased energy conservation (using Aurora model) – Tim Tatum • Areas of agreement and additional information needs *Are there financial disincentives? If so, what is their nature and extent? Is additional information required to assess this?*	Presentations / Discussion
11:45pm	**Lunch** (on your own)	
12:45pm	**Mechanism Evaluation Criteria –** Susan Hayman ***Deferred***	Exercise / Discussion
1:45pm	**Potential Mechanisms to Address Disincentives** ***Deferred*** • True-ups (different kinds?) • Performance Based Incentives (different kinds?) • Others?	Brainstorming exercise / Discussion
2:30pm	**Next Steps, Action Items, Evaluation** – Susan Hayman	Discussion
3:30pm	**Adjourn**	

APPENDIX 3—REVISED OPERATIONAL PROTOCOLS

041108

Workshop Series – Operational Protocol

Workshop Name: Assessing Financial Disincentives and Resolution Opportunities

Workshop Purpose:

1) To investigate the nature and extent of financial disincentives to investment in energy efficiency by Idaho Power Company and customers;
2) To investigate decoupling and performance-based ratemaking (incentives) as mechanisms to address financial disincentives (IPUC Order # 29558, 8/10/2004). *Other mechanisms can be subsequently explored if the participants agree that this would be useful.*

Workshop Products: A written report to the Idaho Public Utilities Commission to update the Commission on the status of the investigative workshops. This report will include a summarized assessment of:

1) The nature and extent of financial disincentives to investment in energy efficiency by Idaho Power Company;
2) Recommendations regarding specific decoupling and/or performance-based mechanisms that may reduce/remove these financial disincentives.
3) Recommendations for next steps.

Workshop Tenure: August 24 through December 15, 2004

---

1) **Composition of Workshop Participants**

   While workshops will be open to the public, it is expected that participants will generally represent the Idaho Public Utilities Commission, Idaho Power Company, Northwest Energy Coalition, representatives of industrial customers, representatives of residential customers, and representatives of irrigation customers.

2) **Roles & Responsibilities of Workshop Participants**
   a) Be active in the discussion, be solutions-oriented, and act in "good-faith."
   b) Help others at the table to understand your interests, and actively seek to understand the interests of others.
   c) Be informed – Review the previous workshop summary, the agenda and prework in advance of the next workshop.
   d) Follow-through in a timely manner with any assigned action items.
   e) Attend workshops regularly – the group will not revisit decisions/discussions missed by others.
   f) **Workshop Coordinators:** One representative each from Idaho Power Company (Mike Youngblood), Idaho Public Utility Commission (Lynn Anderson), Northwest Energy Coalition (Bill Eddie), and industrial customers (Peter Richardson). Responsibilities include coordination with the facilitator on the workshop objectives, outcomes, agenda and process.

3) **Role & Responsibilities of the Facilitator**
   a) Manage the workshops, serve as a process coach, maintain neutrality and impartiality, and reinforce the collaborative process.
   b) Refine the objectives and outcomes for each workshop, in cooperation with the workshop coordinators. Propose a workshop agenda and appropriate processes to reach the identified

Page 1 of 1 – Operational Protocol

041108

objectives and outcomes, and finalize this with the coordinators. The agenda, and any prework materials, will be distributed to participants at least one week prior to each workshop.

c) Communicate with participants outside of workshops as needed.

d) Maintain a record of workshop participants, and a summary of workshop discussions (see #6, Record Keeping).

e) Assist in preparation/compilation of the written report to the Idaho Public Utilities Commission.

4) **Analysis**

Analysis needs will be identified and assigned as they emerge.

5) **Decision-Making**

a) **Entities with multiple representatives:** While each individual participant will have input into the workshop deliberations, it is desirable that each entity represented speak with one voice in decision-making. Therefore, while numerous individuals may represent a given entity at a workshop, it is expected that one person will speak on behalf of the entity when decisions are made. Each entity should designate that person in advance. The facilitator will provide time for representatives to consult with each other as needed prior to critical decisions.

b) **Types of decisions:** There are two types of decisions participants will make:

- *Workshop decisions:* These decisions are related to workshop topics, process and schedule. Workshop decisions already made by the IPUC in Orders 29505 and 29558 will be honored. Decisions at the discretion of the group will be made by consensus.
- *Product decisions:* These decisions are related to the findings and recommendations workshop participants will present in their written report to the IPUC on December 15, 2004. Consensus will be the goal – However, if consensus cannot be reached, areas of agreement and disagreement on the findings and recommendations will be provided in the written report.

6) **Record-Keeping**

a) The facilitator will arrange for notes to be taken on a laptop computer during the workshop. The distributed workshop will include key discussion points, decisions, areas of agreement and disagreement, action items, etc. They will not be a transcription of "who said what."

b) The facilitator will be responsible for preparing the workshop summary and distributing it to participants within three business days after each workshop.

c) The facilitator will maintain a file of all workshop summaries, handouts, and products.

7) **Principles of Meeting Conduct**

a) Focus attention on the speaker (no side conversations)

b) Be specific, but succinct, in questions and comments

c) Participate fully, but don't dominate the discussion.

d) Respect other's contributions, and learn from them.

e) Challenge ideas, not people

f) Be on time

g) Turn cell phones, pagers or other electronic devices off or inaudible during meetings.

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APPENDIX 4—POSTERS WITH OPERATIONAL INFORMATION

Principles of Meeting Conduct

1) Focus attention on the speaker (no side conversations)
2) Be specific, but succinct, in questions and comments
3) Participate fully, but don't dominate the discussion
4) Respect others' contributions, and learn from them
5) Challenge ideas, not people
6) Be on time
7) Turn cell phones, pagers or other electronic devices off or inaudible during meetings

Workshop Series—Purpose and Products

(excerpts from Operational Protocol, adopted 9/27/04)

Workshop Purpose:

1) To investigate the nature and extent of financial disincentives to investment in energy efficiency by Idaho Power Company and customers;
2) To investigate decoupling and performance-based ratemaking (incentives) as mechanisms to address financial disincentives (IPUC Order #29558, 8/10/2004). *Other mechanisms can be subsequently explored if the participants agree that this would be useful.*

Workshop Products: A written report to the Idaho Public Utilities Commission to update the Commission on the status of the investigative workshops. This report will include a summarized assessment of:

1) The nature and extent of financial disincentives to investment in energy efficiency by Idaho Power Company;
2) Recommendations regarding specific decoupling and/or performance-based mechanisms that may reduce/remove these financial disincentives;
3) Recommendations for next steps.

Definitions

Demand Side Management (DSM): Management tools and actions that are designed to result in decreases or shifts in customer energy demand and/or consumption.

Performance-Based Incentives (PBI): Mechanisms that allow a utility to share and retain benefits gained from energy efficiencies, as well as provide consequences for failing to meet efficiency goals.

Decoupling: Severing the link between a utility's kWh sales and its recovery of revenues to cover fixed costs.

True-Up: A decoupling mechanism where a periodic adjustment in electric rates is used to correct for disparities between a utility's actual fixed cost recovery and its authorized fixed cost recovery.

APPENDIX 5—ANDERSON'S RECALCULATION OF FIXED COST REVENUE LOSS USING IRP INFORMATION AND THREE INTERIM RATE CASES

IPC DSM F-C Revenue Loss - IRP with 3 rate cases (REVISED 10/29/04)

DSM Selected in the 2004 IRP *(2004-2013 Planning Period)*
Idaho Power IPC-E-04-018, IRP Technical Appendix
MWh Energy Savings, Net of Free Riders, Incl. Losses, Excl. NEEA

	Year	Residential	Commercial	Irrigation	Industrial	Total MWh
	2005	1,070	389	5,767	9,427	16,653
	2006	2,625	1,087	11,534	18,853	34,100
	2007	4,193	1,900	17,300	28,280	51,674
	2008	5,784	2,810	23,067	37,706	69,367
	2009	7,397	3,801	28,834	47,133	87,166
	2010	9,205	4,851	34,601	56,559	105,226
	2011	11,028	5,980	40,368	65,986	123,363
	2012	12,872	7,149	46,134	75,412	141,566
End of IRP Planning Period	2013	14,734	8,359	51,901	84,839	159,833
					aMW (2004 IRP)=	18.25
	Total	68,908	36,337	259,506	424,195	788,946
Normaliz. MWh	2003	4,141,393	2,932,712	1,620,931	2,325,875	11,020,911
IRP Avg. Growth/Year		1.9%	3.2%	0.2%	3.0%	2.2%

(Numbers by IPC 9/21/04)
Peak Reduction (MW)

Res.	Com.	Irrig.	Ind.	Total
0.6	0.1	2.9	1.2	4.9
1.5	0.4	5.8	2.4	10.1
2.5	0.7	8.7	3.6	15.4
3.4	1.1	11.5	4.8	20.8
4.3	1.5	14.4	6.0	26.2
5.3	1.9	17.3	7.2	31.7
6.3	2.4	20.2	8.4	37.2
7.3	2.8	23.1	9.6	42.8
8.3	3.3	26.0	10.8	48.3
8.3	3.3	26.0	10.8	48.3
Peak MW (Energy Programs)				48.3
Peak MW (Demand Response)				75.6
Total Peak MW Selected DSM				123.9

Calculation of 2003 Rate Case Test Year Fixed-Cost Lost Revenue per MWh for Various Rate Schedules

	Residential	Commercial*	Irrigation	Industrial**
Energy Rate ($/MWh)	51.9	30.0	32.6	21.8
Variable Cost ($/MWh)	20.7	20.3	23.5	18.5
Loss/MWh unsold	**$31.20**	**$9.70**	**$9.10**	**$3.30**

(*) Commercial rate is a weighted avg. of schedules 07 & 09S based on energy use.
(**) Ind. rate is a wghtd. avg. of schs. 09 P & T and 19 S, P & T based on energy use.

Note that the $/MWH here are diff for com. & indust. than on NWPCC sheet.
The losses/MWh are increased as result of each rate case by IRP average growth per year.

Fixed Costs Not Recovered Due to DSM Selected in IRP

Year	Residential	Commercial	Irrigation	Industrial	Total
2005	$33,370	$3,775	$52,480	$31,109	$120,734
2006	81,905	10,548	104,959	62,215	259,627
1st rate case resets rates to recover MWh savings through June 2006.					
2007	76,713	12,195	79,104	50,255	218,267
2008	128,725	21,742	131,846	83,756	366,070
2009	181,473	32,146	184,588	117,260	515,468
2nd rate case resets rates to recover MWh savings through June 2009.					
2010	90,443	17,945	79,585	54,919	242,893
2011	153,542	30,848	132,642	91,535	408,567
2012	217,329	44,322	185,690	128,146	575,487
3rd rate case resets rates to recover MWh savings through June 2012.					
2013	101,957	22,752	80,053	100,012	304,774
9-yearTotal	$1,065,457	$196,274	$1,030,949	$719,207	$3,011,886
				Avg. Annual	$334,654
			WACC = 7.20%		
				PV 9-yr. (2005-2013)	$2,134,081
				Levelized (9-yr.)	$319,061

The fixed-costs not recoverd are the product of multiplying each year's energy savings in the top box by the loss/MWh unsold in the middle box (IPC adj. of Eric Hirst numbers and later years rate case est. changes). The "losses" are not adjusted for income taxes, cost changes, any offsetting benefits, etc. and do not include demand charge fixed-cost revenue losses. With each rate case annual losses are reset to zero, except with 6-month rate case lag, and fixed cost losses per MWh are increased by IRP avg. MWh growth in each class.

APPENDIX 6—ANDERSON'S RECALCULATION OF FIXED COST REVENUE LOSS USING NWPCC INFORMATION AND THREE INTERIM RATE CASES

NWPCC Draft 5th Plan -- Not Reviewed By Council
Achievable, Cost-Effective DSM Potential by 2025

IPC DSM F-C Revenue Loss - NWPCC with three rate cases

			Northwest Potential DSM 20-Year aMW	IPC's 20-yr. aMW @ 6.50%	IPC's annual aMW	IPC's annual MWh	2005	2006	RATE CASE REDUCES F-C REV. LOSS	2007	2008	2009	RATE CASE REDUCES F-C REV. LOSS	2010	2011	2012	RATE CASE REDUCES F-C REV. LOSS	2013	Total 9-year F-C Rev. Loss
Res.	Refrigerators		5																
Res.	Clothes Washers		135																
Res.	Dishwashers		10																
Res.	Water Heaters		80																
Res.	H.P. Water Heaters		195																
Res.	H.W. Heat Recovery		20																
Res.	Compact Flourescent		535																
Res.	New Space Cond.		40																
Res.	Existing Space Cond.		95																
Res.	HVAC Upgrades		65																
Res.	HVAC Conversion		70																
Res.	HVAC Commission		20																
	Res. Total	44.8%	1,270	82.6	4.13	36,157	$1.1	$2.3		$1.8	$3.0	$4.1		$1.9	$3.1	$4.4		$2.0	$23.6
Com.	Equipment, new/repl.		85																
Com.	HVAC, new/repl.		150																
Com.	Infrastructure, new/repl.		20																
Com.	Lighting, new/repl.		245																
Com.	Shell, new/repl.		15																
Com.	Equipment, retrofit		110																
Com.	HVAC, retrofit		120																
Com.	Infrastructure, retrofit		110																
Com.	Lighting, retrofit		115																
Com.	Shell, retrofit		10																
	AC/DC power conv.		155																
	Com. Total	40.0%	1,135	73.8	3.69	32,313	$1.3	$2.7		$2.2	$3.6	$5.1		$2.4	$4.0	$5.6		$2.6	$29.5
Irrig.	All Agriculture		80																
	Irrig. Total	2.8%	80	5.2	0.26	2,278	$0.0	$0.0		$0.0	$0.1	$0.1		$0.0	$0.1	$0.1		$0.0	$0.4
Ind.	All Non-Aluminum		350																
	Ind. Total	12.3%	350	22.8	1.14	9,965	$0.0	$0.1		$0.1	$0.1	$0.2		$0.1	$0.1	$0.2		$0.1	$1.1
	Total	100.0%	2,835	184.3	9.21	80,712	$2.5	$5.1		$4.1	$6.8	$9.5		$4.4	$7.3	$10.2		$4.7	$54.6

$6.1 Avg. Annual
WACC = 7.20%
$39.0 *PV 9-yr. (2005-2013)*
$6.0 Levelized (9-yr.)

$/MWh From IPC's 3/30/04 Eric Hirst Decoupling Report, p. 5 -- IPC Updated

	Res.	Com. -7	Irrig.	Indust. -all 9 & 19 sch. (wt. avg.)	
Energy Charge	51.90	62.60	32.60	24.40	Note that the $/MWH here
Variable Cost	20.70	21.10	23.50	19.50	are diff. for com. & Indust.
Loss/MWh unsold	$31.20	$41.50	$9.10	$4.90	than on IRP-selected sheet.

	Res.	Com.	Irrig.	Indust.	Total
IRP Avg. Growth/Year	1.9%	3.2%	0.2%	3.0%	2.2%

Idaho Power's 6.5% share is based on its current NEEA allocation, which may not represent its potential for each program or customer class.

With each rate case, annual losses are reset to zero, except with 6-month rate case lag, and fixed cost losses per MWh are increased by IRP's avg. MWh growth in each class.

APPENDIX 7—CAVANAGH'S RESPONSE TO ANDERSON'S ANALYSES

-------------- Forwarded Message: --------------
From: "Cavanagh, Ralph" <rcavanagh@nrdc.org>
To: "Lynn Anderson" <landers@puc.state.id.us>, <north_country@att.net>, "Randy Lobb" <rlobb@puc.state.id.us>, "Brad Purdy" <bmpurdy@hotmail.com>, "Mike Youngblood" <myoungblood@idahopower.com>, "Greg Said" <gsaid@idahopower.com>, "Bart Kline" <bkline@idahopower.com>, "Ric Gale" <rgale@idahopower.com>, "Dave Schunke" <dschunk@puc.state.id.us>, "Alden Holm" <aholm@puc.state.id.us>, "David Hawk" <david.hawk@simplot.com>, "Bill Eddie" <billeddie@rmci.net>, "Scott Woodbury" <swoodbu@puc.state.id.us>, "Peter Richardson" <peter@richardsonandoleary.com>, "Darlene Nemnich" <dnemnich@idahopower.com>, "Laura Nelson" <lnelson@puc.state.id.us>, "Maggie Brilz" <mbrilz@idahopower.com>, "Terri Carlock" <tcarloc@puc.state.id.us>, "Nancy Hirsh" <nancy@nwenergy.org>, <ttatum@idahopower.com>, <dreading@mindspring.com>
Subject: Comments on Lynn's Analysis
Date: Wed, 3 Nov 2004 23:32:04 +0000
COLLEAGUES:

I am grateful to Lynn for timely circulation of his revised analysis, and (after a discussion with him) offer these additional thoughts:

1. The NWPCC energy efficiency projections, although more aggressive than the Company's current IRP, is not by any means the upper bound of the possible; as a fraction of system electricity use, for example, the Council targets are only about half the targets that California's utilities are planning to meet (equivalent to about one percent of their systemwide retail consumption annually). I would never suggest to this group that Idaho should copy California, but neither would I want to imply that it's impossible for Idaho to OUTPERFORM California.

2. On the question of whether potential revenue losses from increased DSM investments are material, I think that the point is now well established even with Lynn's revised numbers ($54.5 million over nine years sure gets my attention, and for that matter so does $3 million). But I want to emphasize that Lynn's new, somewhat lower numbers reflect a crucial assumption with which I do not agree. As Lynn forthrightly says, his analysis assumes that every time you have a rate case, "forward-looking revenue losses from past DSM efforts are eliminated," "even though past DSM savings are assumed to persist in the future." Here is the difficulty: those persisting DSM savings continue to inflict revenue losses on the Company even after the rate case, in the sense that the unsold kWh return no fixed costs to the Company, and the Company clearly would be better off financially if those old savings disappeared instead of persisting. The only sense in which anything is "eliminated" is that each rate case resets rates based on actual consumption in the year closest to the rate case, so that the sales base <u>for that test year</u> incorporates the impact of previous years' energy efficiency investments <u>in that year</u>. But in subsequent years, if the savings persist, the Company continues to lose revenues COMPARED TO A SCENARIO UNDER WHICH THOSE SAME SAVINGS DISAPPEARED, and Lynn's analysis isn't picking those incremental losses up at all – it's disregarding them (unlike his initial analysis, which counted them). So, in my view, Lynn is understating the losses to the company from persistent savings and missing a

perfectly perverse feature of the status quo: the Company is rewarded for installing short-lived efficiency measures and penalized for finding durable savings. **THIS IS ANOTHER VERY GOOD REASON TO ADOPT A TRUE-UP MECHANISM THAT ELIMINATES THE LINKAGE BETWEEN RETAIL ELECTRICITY CONSUMPTION AND IDAHO POWER'S FIXED COST RECOVERY.**

-----Original Message-----
From: Lynn Anderson [mailto:landers@puc.state.id.us]
Sent: Wednesday, November 03, 2004 1:04 PM
To: north_country@att.net; Randy Lobb; Brad Purdy; Mike Youngblood; Greg Said; Bart Kline; Ric Gale; Dave Schunke; Alden Holm; David Hawk; Cavanagh, Ralph; Bill Eddie; Scott Woodbury; Peter Richardson; Darlene Nemnich; Laura Nelson; Maggie Brilz; Terri Carlock; Nancy Hirsh; ttatum@idahopower.com; dreading@mindspring.com
Subject: Rate Cases Effects on F-C Rev. Losses

Hello, Decoupling Workgroup,

Attached is a two-tab, two-scenario worksheet that calculates fixed-cost revenue losses assuming rate cases occur every three years. (Idaho Power's last rate case test year was 2003.) Under both scenarios, forward-looking revenue losses from past DSM efforts are eliminated (except for an assumed 6-month lag between the end of the rate case test year and rate implementation) even though past DSM savings are assumed to persist into the future. DSM efforts that occur after each rate case test year result in new fixed-cost revenue losses that accrue until the next rate case. Each rate case is assumed to result in the loss per MWh unsold increasing by the IRP-projected average MWh sales growth rate for each customer class.

The first tab shows results under Idaho Power's IRP-level of DSM (which excludes NEEA). The IRP rate-case adjusted, 9-year total fixed cost revenue loss is $3 million compared to $6.2 million shown in the IRP worksheet we reviewed at the September 27 workshop. The present value of the $3 million is about $2 million and the levelized loss is $0.3 million per year.

The second tab shows results under Idaho Power's 6.5% share of the NWPCC-level of DSM (which includes NEEA, fuel conversions, building codes, appliance standards and other DSM for which utilities have limited, little or no control.) The NWPCC rate-case adjusted, 9-year total fixed cost revenue loss is $54.6 million compared to $114.2 million shown in the NWPCC worksheet we reviewed at the September 27 workshop. The present value of the $54.6 million is about $39 million and the levelized loss is $6 million per year.

The analyses in both scenarios are admittedly very simplified, but fairly straightforward. I doubt that adding complexity for greater accuracy would change the results significantly. A brief recap from September's workshop: Ralph Cavanagh pointed out that adding demand-related revenue losses could increase the losses by about 10%, but I countered that accounting for income taxes would reduce them by a greater amount, and Greg Said reminded us that if lost revenues are recovered then the taxes have to also be recovered. In short, I think the two scenarios represent a low-side and a high-side of potential fixed-cost revenue losses, although the possible range is even wider.

Lynn Anderson, IPUC
208-334-0353

APPENDIX 8—MODEL OF RATE IMPACTS BY CLASS UNDER IRP AND NWPCC PROJECTIONS

	RESIDENTIAL												
	Total System			Idaho Jurisdictional Energy 95.62%							Total Fixed Cost per MWH (Class & Subsidy)		
Year	Base Case Energy (MWH)	High Growth Scenario (MWH)	Low Growth Scenario (MWH)	Base Case Energy (MWH)	Base Growth Rate	High Growth Scenario (MWH)	High Growth Rate	Low Growth Scenario (MWH)	Low Growth Rate	Base Rate Class Revenue Requirement	Base Revenue	High Revenue	Low Revenue
				(1)*95.62%		(2)*95.62%		(3)*95.62%		(10)* 1+(5)	(4)*30.14	(6)*30.14	(8)*30.14
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2000	4,313,062			4,124,252	1.47%								
2001	4,347,260			4,156,953	0.79%								
2002	4,290,810			4,102,974	(1.30%)								
Weather Adj. 2003	4,412,329	4,412,329	4,412,329	4,219,174	2.83%	4,219,174		4,219,174		$232,325,720	$127,161,141	$127,161,141	$127,161,141
Forecasted 2004	4,489,282	4,564,106	4,396,051	4,292,758	1.74%	4,363,431	3.89%	4,202,652	(0.39%)	$236,377,565	$129,378,889	$132,111,672	$126,663,194
2005	4,582,514	4,721,392	4,448,392	4,381,909	2.08%	4,514,707	2.99%	4,253,656	1.21%	$241,286,600	$132,065,789	$136,068,181	$128,200,449
2006	4,676,944	4,851,016	4,509,747	4,472,205	2.06%	4,638,656	2.75%	4,312,327	1.38%	$246,258,695	$134,787,215	$139,803,871	$129,968,672
2007	4,768,668	4,974,083	4,572,266	4,559,913	1.96%	4,756,326	2.54%	4,372,109	1.39%	$251,088,308	$137,430,655	$143,350,602	$131,770,445
2008	4,871,780	5,106,854	4,647,871	4,658,512	2.16%	4,883,295	2.67%	4,444,405	1.65%	$256,517,543	$140,402,292	$147,177,019	$133,949,357
2009	4,968,035	5,232,455	4,719,570	4,750,553	1.98%	5,003,397	2.46%	4,512,965	1.54%	$261,585,731	$143,176,314	$150,798,755	$136,015,662
2010	5,054,701	5,344,513	4,780,962	4,833,425	1.74%	5,110,550	2.14%	4,571,670	1.30%	$266,149,022	$145,673,985	$154,028,214	$137,784,973
2011	5,139,976	5,457,405	4,844,535	4,914,996	1.69%	5,218,500	2.11%	4,632,459	1.33%	$270,639,010	$148,131,539	$157,279,705	$139,617,103
2012	5,224,063	5,563,180	4,902,875	4,995,373	1.64%	5,319,645	1.94%	4,688,246	1.20%	$275,066,568	$150,554,914	$160,328,102	$141,298,447
2013	5,309,927	5,676,573	4,968,734	5,077,478	1.64%	5,428,074	2.04%	4,751,222	1.34%	$279,587,631	$153,029,472	$163,596,023	$143,196,499
2014	5,390,551	5,782,785	5,028,905	5,154,573	1.52%	5,529,636	1.87%	4,808,759	1.21%	$283,832,788	$155,353,016	$166,656,992	$144,930,561
2015	5,468,847	5,879,722	5,081,545	5,229,441	1.45%	5,622,329	1.68%	4,859,094	1.05%	$287,955,367	$157,609,468	$169,450,678	$146,447,607
2016	5,549,738	5,988,097	5,144,470	5,306,791	1.48%	5,725,951	1.84%	4,919,264	1.24%	$292,214,582	$159,940,707	$172,574,010	$148,261,073
2017	5,631,660	6,096,385	5,206,711	5,385,127	1.48%	5,829,552	1.79%	4,978,780	1.21%	$296,528,084	$162,301,658	$175,695,996	$150,054,836
2018	5,715,076	6,201,530	5,268,181	5,464,891	1.48%	5,930,050	1.74%	5,037,540	1.18%	$300,920,250	$164,705,666	$178,725,019	$151,825,796
2019	5,798,052	6,306,466	5,328,722	5,544,235	1.45%	6,030,392	1.69%	5,095,450	1.15%	$305,289,248	$167,096,993	$181,749,235	$153,571,129
2020	5,880,483	6,410,125	5,388,300	5,623,057	1.42%	6,129,513	1.64%	5,152,420	1.12%	$309,629,551	$169,472,814	$184,736,639	$155,288,146
2021	5,961,577	6,523,970	5,456,458	5,700,601	1.38%	6,238,374	1.78%	5,217,595	1.26%	$313,899,455	$171,809,703	$188,017,580	$157,252,429
2022	6,042,900	6,625,678	5,514,458	5,778,370	1.36%	6,335,631	1.56%	5,273,055	1.06%	$318,181,732	$174,153,565	$190,948,777	$158,923,944
2023	6,123,598	6,725,893	5,571,232	5,855,530	1.34%	6,431,458	1.51%	5,327,344	1.03%	$322,430,470	$176,479,068	$193,836,914	$160,560,145
2024	6,205,960			5,934,286	1.34%					$326,767,130	$178,852,700		
2025	6,288,814			6,013,513	1.34%					$331,129,714	$181,240,512		

RESIDENTIAL

Year	Demand Side Management		Revenue Recovered at Total Fixed Cost per MWH (Class & Subsidy) Rate less DSM unrecoverd costs								
	Energy Savings (MWH)	Fixed Costs Unrecovered	Base Revenue Recovered	Amount of True-Up (Base)	True-Up Percentage of Revenue Requirement (Base)	High Revenue Recovered	Amount of True-Up (High)	True-Up Percentage of Revenue Requirement (High)	Low Revenue Recovered	Amount of True-Up (Low)	True-Up Percentage of Revenue Requirement (Low)
		(14)*30.14	(11) - (15)	(11) - (16)	(17) / (10)	(12) - (15)	(11) - (19)	(20)/(10)	(13) - (15)	(11) - (22)	(23)/(10)
	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)
2000											
2001											
2002											
Weather Adj. 2003											
Forecasted 2004	0	$0	$129,378,889	$0	0.00%	$132,111,672	($2,732,783)	(1.16%)	$126,663,194	$2,715,695	1.15%
2005	25,229	$760,368	$131,305,421	$760,368	0.32%	$135,307,813	($3,242,024)	(1.34%)	$127,440,082	$4,625,707	1.92%
2006	51,859	$1,562,978	$133,224,237	$1,562,978	0.63%	$138,240,893	($3,453,678)	(1.40%)	$128,405,694	$6,381,520	2.59%
2007	79,891	$2,407,831	$135,022,824	$2,407,831	0.96%	$140,942,771	($3,512,116)	(1.40%)	$129,362,614	$8,068,041	3.21%
2008	109,325	$3,294,926	$137,107,366	$3,294,926	1.28%	$143,882,093	($3,479,801)	(1.36%)	$130,654,431	$9,747,861	3.80%
2009	140,160	$4,224,265	$138,952,049	$4,224,265	1.61%	$146,572,491	($3,396,177)	(1.30%)	$131,791,417	$11,384,896	4.35%
2010	173,798	$5,238,088	$140,435,897	$5,238,088	1.97%	$148,788,126	($3,114,141)	(1.17%)	$132,546,885	$13,127,100	4.93%
2011	208,838	$6,294,154	$141,837,385	$6,294,154	2.33%	$150,985,550	($2,854,011)	(1.05%)	$133,322,948	$14,808,591	5.47%
2012	245,280	$7,392,463	$143,162,451	$7,392,463	2.69%	$152,935,639	($2,380,725)	(0.87%)	$133,905,984	$16,648,930	6.05%
2013	282,843	$8,524,566	$144,504,906	$8,524,566	3.05%	$155,071,457	($2,041,985)	(0.73%)	$134,671,900	$18,357,572	6.57%
2014	282,843	$8,524,566	$146,828,450	$8,524,566	3.00%	$158,132,427	($2,779,411)	(0.98%)	$136,405,995	$18,947,021	6.68%
2015	282,843	$8,524,566	$149,084,902	$8,524,566	2.96%	$160,926,112	($3,316,644)	(1.15%)	$137,923,042	$19,686,426	6.84%
2016	282,843	$8,524,566	$151,416,141	$8,524,566	2.92%	$164,049,444	($4,108,737)	(1.41%)	$139,736,507	$20,204,199	6.91%
2017	282,843	$8,524,566	$153,777,092	$8,524,566	2.87%	$167,141,430	($4,839,772)	(1.63%)	$141,530,261	$20,771,398	7.00%
2018	282,843	$8,524,566	$156,181,100	$8,524,566	2.83%	$170,200,453	($5,494,787)	(1.83%)	$143,301,230	$21,404,436	7.11%
2019	282,843	$8,524,566	$158,572,427	$8,524,566	2.79%	$173,224,669	($6,127,675)	(2.01%)	$145,046,563	$22,050,431	7.22%
2020	282,843	$8,524,566	$160,948,048	$8,524,566	2.75%	$176,212,063	($6,739,449)	(2.18%)	$146,763,580	$22,709,034	7.33%
2021	282,843	$8,524,566	$163,285,137	$8,524,566	2.72%	$179,493,014	($7,683,311)	(2.45%)	$148,727,864	$23,081,839	7.35%
2022	282,843	$8,524,566	$165,628,999	$8,524,566	2.68%	$182,424,211	($8,270,646)	(2.60%)	$150,399,378	$23,754,187	7.47%
2023	282,843	$8,524,566	$167,954,502	$8,524,566	2.64%	$185,312,348	($8,833,280)	(2.74%)	$152,035,579	$24,443,490	7.58%
2024											
2025											

COMMERCIAL

Year	Total System			Idaho Jurisdictional Energy 94.28%							Total Fixed Cost per MWH (Class & Subsidy)		
	Base Case Energy (MWH)	High Growth Scenario (MWH)	Low Growth Scenario (MWH)	Base Case Energy (MWH)	Base Growth Rate	High Growth Scenario (MWH)	High Growth Rate	Low Growth Scenario (MWH)	Low Growth Rate	Base Rate Class Revenue Requirement	Base Revenue	High Revenue	Low Revenue
				(1)*94.28%		(2)*94.28%		(3)*94.28%		(10)* 1+(5)	(4)*8.29	(6)*8.29	(8)*8.29
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2000	3,315,897			3,126,335	4.73%								
2001	3,465,295			3,267,193	4.51%								
2002	3,420,879			3,225,315	(1.28%)								
Weather Adj. 2003	3,491,588	3,491,588	3,491,588	3,291,982	2.07%	3,291,982		3,291,982		$129,540,066	$27,295,897	$27,295,897	$27,295,897
Forecasted 2004	3,645,464	3,772,139	3,537,754	3,437,051	4.41%	3,556,494	8.04%	3,335,508	1.32%	$135,248,060	$28,498,841	$29,489,137	$27,656,802
2005	3,800,328	3,976,291	3,631,433	3,583,072	4.25%	3,748,875	5.41%	3,423,832	2.65%	$140,994,510	$29,709,508	$31,085,118	$28,389,150
2006	3,933,811	4,158,117	3,720,845	3,708,924	3.51%	3,920,407	4.57%	3,508,133	2.46%	$145,945,812	$30,753,027	$32,506,567	$29,088,143
2007	4,067,539	4,337,086	3,814,853	3,835,007	3.40%	4,089,144	4.30%	3,596,766	2.53%	$150,908,203	$31,798,461	$33,905,674	$29,823,059
2008	4,206,242	4,518,237	3,914,461	3,965,781	3.41%	4,259,940	4.18%	3,690,080	2.61%	$156,054,170	$32,882,788	$35,321,848	$30,601,754
2009	4,339,800	4,694,460	4,011,831	4,091,703	3.18%	4,426,089	3.90%	3,782,484	2.49%	$161,009,254	$33,926,894	$36,699,493	$31,382,959
2010	4,467,278	4,862,165	4,103,163	4,211,894	2.94%	4,584,205	3.57%	3,868,595	2.28%	$165,739,766	$34,923,468	$38,010,545	$32,076,960
2011	4,594,090	5,030,720	4,195,946	4,331,456	2.84%	4,743,125	3.47%	3,956,073	2.26%	$170,443,569	$35,914,835	$39,328,241	$32,802,298
2012	4,721,005	5,198,714	4,288,601	4,451,116	2.76%	4,901,515	3.34%	4,043,431	2.21%	$175,152,194	$36,907,008	$40,641,553	$33,526,638
2013	4,849,664	5,367,576	4,382,045	4,572,420	2.73%	5,060,723	3.25%	4,131,533	2.18%	$179,925,522	$37,912,815	$41,961,650	$34,257,147
2014	4,975,937	5,532,987	4,472,580	4,691,474	2.60%	5,216,678	3.08%	4,216,893	2.07%	$184,610,328	$38,899,969	$43,254,789	$34,964,917
2015	5,102,926	5,701,109	4,565,088	4,811,203	2.55%	5,375,190	3.04%	4,304,112	2.07%	$189,321,699	$39,892,720	$44,569,087	$35,688,109
2016	5,232,760	5,873,754	4,660,846	4,933,615	2.54%	5,537,965	3.03%	4,394,396	2.10%	$194,138,620	$40,907,713	$45,918,759	$36,436,706
2017	5,363,632	6,044,709	4,754,802	5,057,005	2.50%	5,699,147	2.91%	4,482,981	2.00%	$198,904,052	$41,930,820	$47,255,220	$37,171,223
2018	5,496,151	6,222,686	4,853,737	5,181,949	2.47%	5,866,849	2.94%	4,576,259	2.08%	$203,910,588	$42,966,803	$48,646,577	$37,944,654
2019	5,628,971	6,400,034	4,951,559	5,307,175	2.42%	6,034,159	2.85%	4,668,459	2.02%	$208,838,292	$44,005,139	$50,033,017	$38,709,388
2020	5,762,721	6,576,487	5,048,052	5,433,279	2.38%	6,200,524	2.76%	4,759,467	1.95%	$213,800,500	$45,050,745	$51,412,458	$39,463,739
2021	5,896,856	6,751,767	5,143,006	5,559,746	2.33%	6,365,783	2.67%	4,848,992	1.88%	$218,776,991	$46,099,361	$52,782,725	$40,206,052
2022	6,032,810	6,938,385	5,245,688	5,687,926	2.31%	6,541,733	2.76%	4,945,962	2.00%	$223,820,968	$47,162,197	$54,241,632	$41,010,343
2023	6,168,940	7,125,303	5,348,219	5,816,276	2.26%	6,717,965	2.69%	5,042,473	1.95%	$228,871,475	$48,226,409	$55,702,889	$41,810,328
2024	6,307,941			5,947,330	2.25%					$234,028,497	$49,313,066		
2025	6,448,030			6,079,976	2.23%					$239,240,148	$50,412,919		

	COMMERCIAL										
	Demand Side Management		Revenue Recovered at Total Fixed Cost per MWH (Class & Subsidy) Rate less DSM unrecoverd costs								
Year	Energy Savings (MWH)	Fixed Costs Unrecovered	Base Revenue Recovered	Amount of True-Up (Base)	True-Up Percentage of Revenue Requirement (Base)	High Revenue Recovered	Amount of True-Up (High)	True-Up Percentage of Revenue Requirement (High)	Low Revenue Recovered	Amount of True-Up (Low)	True-Up Percentage of Revenue Requirement (Low)
	(14)	(14)*8.29 (15)	(11) - (15) (16)	(11) - (16) (17)	(17) / (10) (18)	(12) - (15) (19)	(11) - (19) (20)	(20)/(10) (21)	(13) - (15) (22)	(11) - (22) (23)	(23)/(10) (24)
2000											
2001											
2002											
Weather Adj. 2003											
Forecasted 2004	0	$0	$28,498,841	$0	0.00%	$29,439,137	($990,296)	(0.73%)	$27,656,802	$842,038	0.62%
2005	22,426	$185,945	$29,523,563	$185,945	0.13%	$30,899,173	($1,189,665)	(0.84%)	$28,203,206	$1,506,303	1.07%
2006	46,253	$383,511	$30,369,516	$383,511	0.26%	$32,123,056	($1,370,029)	(0.94%)	$28,704,632	$2,048,395	1.40%
2007	71,482	$592,699	$31,205,762	$592,699	0.39%	$33,312,975	($1,514,514)	(1.00%)	$29,230,380	$2,568,101	1.70%
2008	98,112	$813,508	$32,069,280	$813,508	0.52%	$34,508,338	($1,625,549)	(1.04%)	$29,788,246	$3,094,542	1.98%
2009	126,144	$1,045,939	$32,880,954	$1,045,939	0.65%	$35,653,553	($1,726,659)	(1.07%)	$30,317,020	$3,609,874	2.24%
2010	156,979	$1,301,614	$33,621,854	$1,301,614	0.79%	$36,708,931	($1,785,463)	(1.09%)	$30,775,347	$4,148,121	2.50%
2011	189,216	$1,568,909	$34,345,926	$1,568,909	0.92%	$37,759,332	($1,844,497)	(1.08%)	$31,233,389	$4,681,447	2.75%
2012	222,854	$1,847,826	$35,059,182	$1,847,826	1.05%	$38,793,726	($1,886,710)	(1.08%)	$31,678,811	$5,228,197	2.98%
2013	257,614	$2,136,041	$35,776,774	$2,136,041	1.19%	$39,825,609	($1,912,794)	(1.06%)	$32,121,106	$5,791,709	3.22%
2014	257,614	$2,136,041	$36,763,928	$2,136,041	1.16%	$41,118,728	($2,218,759)	(1.20%)	$32,828,876	$6,071,093	3.29%
2015	257,614	$2,136,041	$37,756,679	$2,136,041	1.13%	$42,433,047	($2,540,328)	(1.34%)	$33,552,068	$6,340,652	3.35%
2016	257,614	$2,136,041	$38,771,672	$2,136,041	1.10%	$43,782,718	($2,875,005)	(1.48%)	$34,300,667	$6,607,046	3.40%
2017	257,614	$2,136,041	$39,794,779	$2,136,041	1.07%	$45,119,179	($3,188,359)	(1.60%)	$35,035,182	$6,895,638	3.47%
2018	257,614	$2,136,041	$40,830,762	$2,136,041	1.05%	$46,510,536	($3,543,734)	(1.74%)	$35,808,613	$7,158,190	3.51%
2019	257,614	$2,136,041	$41,869,098	$2,136,041	1.02%	$47,896,976	($3,891,838)	(1.88%)	$36,573,347	$7,431,791	3.56%
2020	257,614	$2,136,041	$42,914,704	$2,136,041	1.00%	$49,276,415	($4,225,670)	(1.98%)	$37,327,698	$7,723,047	3.61%
2021	257,614	$2,136,041	$43,963,320	$2,136,041	0.98%	$50,646,664	($4,547,323)	(2.08%)	$38,070,011	$8,029,350	3.67%
2022	257,614	$2,136,041	$45,026,156	$2,136,041	0.95%	$52,105,591	($4,943,394)	(2.21%)	$38,874,302	$8,287,895	3.70%
2023	257,614	$2,136,041	$46,090,368	$2,136,041	0.93%	$53,566,848	($5,340,438)	(2.33%)	$39,674,287	$8,552,122	3.74%
2024											
2025											

	INDUSTRIAL												
	Total System			Idaho Jurisdictional Energy 88.64%							Total Fixed Cost per MWH (Class & Subsidy)		
Year	Base Case Energy (MWH)	High Growth Scenario (MWH)	Low Growth Scenario (MWH)	Base Case Energy (MWH)	Base Growth Rate	High Growth Scenario (MWH)	High Growth Rate	Low Growth Scenario (MWH)	Low Growth Rate	Base Rate Class Revenue Requirement	Base Revenue	High Revenue	Low Revenue
				(1)*88.64%		(2)*88.64%		(3)*88.64%		(10)* 1+(5)	(4)*2.44	(6)*2.44	(8)*2.44
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2000	2,191,471			1,942,523	1.45%								
2001	2,288,638			2,028,652	4.43%								
2002	2,156,428			1,911,461	(5.76%)								
Weather Adj. 2003	2,234,497	2,234,497	2,234,497	1,980,662	3.62%	1,980,662		1,980,662		$56,713,726	$4,825,631	$4,825,631	$4,825,631
Forecasted 2004	2,295,846	2,407,973	2,204,069	2,035,043	2.75%	2,134,431	7.76%	1,953,691	(1.36%)	$58,270,883	$4,958,125	$5,200,270	$4,759,919
2005	2,373,974	2,527,062	2,229,635	2,104,294	3.40%	2,239,992	4.95%	1,976,530	1.17%	$60,253,798	$5,126,846	$5,457,455	$4,815,564
2006	2,452,481	2,647,881	2,271,482	2,173,883	3.31%	2,340,909	4.77%	2,013,445	1.87%	$62,246,383	$5,296,390	$5,717,945	$4,905,504
2007	2,533,350	2,767,939	2,319,017	2,245,566	3.30%	2,453,506	4.54%	2,055,580	2.09%	$64,298,918	$5,471,035	$5,977,655	$5,008,160
2008	2,608,959	2,880,033	2,363,546	2,312,585	2.98%	2,553,297	4.07%	2,095,051	1.92%	$66,217,949	$5,634,321	$6,221,028	$5,104,325
2009	2,683,932	2,990,847	2,408,071	2,379,042	2.87%	2,651,092	3.83%	2,134,518	1.88%	$68,120,838	$5,796,233	$6,459,048	$5,200,462
2010	2,765,009	3,108,242	2,459,588	2,450,908	3.02%	2,755,239	3.93%	2,180,182	2.14%	$70,178,652	$5,971,327	$6,712,791	$5,311,738
2011	2,845,845	3,225,361	2,511,279	2,522,562	2.92%	2,858,983	3.77%	2,226,002	2.10%	$72,230,349	$6,145,901	$6,965,548	$5,423,370
2012	2,924,852	3,340,965	2,562,081	2,592,594	2.78%	2,961,437	3.58%	2,271,033	2.02%	$74,235,624	$6,316,525	$7,215,164	$5,533,084
2013	3,006,130	3,457,252	2,613,463	2,663,752	2.74%	3,064,514	3.48%	2,316,577	2.01%	$76,273,159	$6,489,893	$7,466,298	$5,644,047
2014	3,088,500	3,578,065	2,668,103	2,737,651	2.77%	3,171,603	3.49%	2,365,011	2.09%	$78,309,172	$6,669,940	$7,727,207	$5,762,048
2015	3,171,256	3,696,226	2,720,482	2,811,006	2.68%	3,276,341	3.30%	2,411,440	1.96%	$80,489,601	$6,848,660	$7,982,388	$5,875,166
2016	3,253,963	3,815,043	2,773,010	2,884,318	2.61%	3,381,661	3.21%	2,458,000	1.93%	$82,588,766	$7,027,274	$8,238,986	$5,988,605
2017	3,338,927	3,939,807	2,829,418	2,959,630	2.61%	3,492,251	3.27%	2,507,999	2.03%	$84,745,256	$7,210,762	$8,508,426	$6,110,421
2018	3,424,409	4,068,208	2,886,457	3,035,402	2.56%	3,604,293	3.21%	2,558,560	2.02%	$86,914,673	$7,395,370	$8,781,402	$6,233,606
2019	3,509,178	4,187,711	2,939,466	3,110,541	2.49%	3,711,994	2.99%	2,605,565	1.84%	$89,066,394	$7,578,438	$9,043,802	$6,348,129
2020	3,597,642	4,316,710	2,997,209	3,188,956	2.52%	3,826,338	3.08%	2,656,731	1.96%	$91,311,897	$7,769,485	$9,322,387	$6,472,787
2021	3,688,754	4,447,246	3,055,357	3,269,718	2.53%	3,942,046	3.02%	2,708,274	1.94%	$93,624,210	$7,966,251	$9,604,293	$6,598,365
2022	3,782,050	4,587,751	3,119,632	3,352,415	2.53%	4,066,590	3.16%	2,765,247	2.10%	$95,992,154	$8,167,734	$9,907,729	$6,737,172
2023	3,874,569	4,721,946	3,178,673	3,434,424	2.45%	4,185,540	2.93%	2,817,758	1.90%	$98,340,377	$8,367,538	$10,197,537	$6,865,110
2024	3,966,376			3,515,802	2.37%					$100,670,529	$8,565,805		
2025	4,059,270			3,598,143	2.34%					$103,028,271	$8,766,419		

	INDUSTRIAL										
	Demand Side Management		Revenue Recovered at Total Fixed Cost per MWH (Class & Subsidy) Rate less DSM unrecoverd costs								
Year	Energy Savings (MWH)	Fixed Costs Unrecovered	Base Revenue Recovered	Amount of True-Up (Base)	True-Up Percentage of Revenue Requirement (Base)	High Revenue Recovered	Amount of True-Up (High)	True-Up Percentage of Revenue Requirement (High)	Low Revenue Recovered	Amount of True-Up (Low)	True-Up Percentage of Revenue Requirement (Low)
	(14)	(14)*2.44 (15)	(11) - (15) (16)	(11) - (16) (17)	(17) / (10) (18)	(12) - (15) (19)	(11) - (19) (20)	(20)/(10) (21)	(13) - (15) (22)	(11) - (22) (23)	(23)/(10) (24)
2000											
2001											
2002											
Weather Adj. 2003											
Forecasted 2004	0	$0	$4,958,125	$0	0.00%	$5,200,270	($242,145)	(0.42%)	$4,759,919	$440,351	0.76%
2005	19,622	$47,807	$5,079,038	$47,807	0.08%	$5,409,647	($282,801)	(0.47%)	$4,767,756	$689,699	1.14%
2006	39,245	$95,615	$5,200,775	$95,615	0.15%	$5,622,330	($325,940)	(0.52%)	$4,809,889	$908,056	1.46%
2007	58,867	$143,422	$5,327,613	$143,422	0.22%	$5,834,233	($363,198)	(0.58%)	$4,864,738	$1,112,917	1.73%
2008	78,490	$191,230	$5,443,091	$191,230	0.29%	$6,029,798	($395,478)	(0.60%)	$4,913,095	$1,307,933	1.98%
2009	98,112	$239,037	$5,557,195	$239,037	0.35%	$6,220,011	($423,778)	(0.62%)	$4,961,445	$1,497,603	2.20%
2010	117,734	$286,845	$5,684,482	$286,845	0.41%	$6,425,946	($454,619)	(0.65%)	$5,024,893	$1,687,898	2.41%
2011	137,357	$334,652	$5,811,246	$334,652	0.46%	$6,630,896	($484,998)	(0.67%)	$5,088,718	$1,876,831	2.60%
2012	156,979	$382,460	$5,934,065	$382,460	0.52%	$6,832,704	($516,180)	(0.70%)	$5,150,624	$2,064,540	2.78%
2013	176,602	$430,267	$6,059,626	$430,267	0.56%	$7,036,030	($546,137)	(0.72%)	$5,213,779	$2,252,518	2.95%
2014	176,602	$430,267	$6,239,672	$430,267	0.55%	$7,296,940	($627,000)	(0.80%)	$5,331,781	$2,395,427	3.06%
2015	176,602	$430,267	$6,418,393	$430,267	0.53%	$7,552,121	($703,461)	(0.87%)	$5,444,899	$2,537,489	3.15%
2016	176,602	$430,267	$6,597,007	$430,267	0.52%	$7,808,719	($781,444)	(0.95%)	$5,558,338	$2,680,648	3.25%
2017	176,602	$430,267	$6,780,496	$430,267	0.51%	$8,078,159	($867,396)	(1.02%)	$5,680,153	$2,828,273	3.34%
2018	176,602	$430,267	$6,965,103	$430,267	0.50%	$8,351,134	($955,764)	(1.10%)	$5,803,338	$2,978,063	3.43%
2019	176,602	$430,267	$7,148,171	$430,267	0.48%	$8,613,535	($1,035,097)	(1.16%)	$5,917,862	$3,125,940	3.51%
2020	176,602	$430,267	$7,339,218	$430,267	0.47%	$8,892,120	($1,122,635)	(1.23%)	$6,042,520	$3,279,867	3.59%
2021	176,602	$430,267	$7,535,984	$430,267	0.46%	$9,174,026	($1,207,775)	(1.29%)	$6,168,097	$3,436,196	3.67%
2022	176,602	$430,267	$7,737,466	$430,267	0.45%	$9,477,462	($1,309,728)	(1.36%)	$6,306,905	$3,600,824	3.75%
2023	176,602	$430,267	$7,937,271	$430,267	0.44%	$9,767,269	($1,399,731)	(1.42%)	$6,434,843	$3,762,694	3.83%
2024											
2025											

IRRIGATION													
	Total System			Idaho Jurisdictional Energy 97.36%								Total Fixed Cost per MWH (Class & Subsidy)		
Year	Base Case Energy (MWH)	High Growth Scenario (MWH)	Low Growth Scenario (MWH)	Base Case Energy (MWH)	Base Growth Rate	High Growth Scenario (MWH)	High Growth Rate	Low Growth Scenario (MWH)	Low Growth Rate	Base Rate Class Revenue Requirement	Base Revenue	High Revenue	Low Revenue
				(1)*97.36%		(2)*97.36%		(3)*97.36%		(10)* 1+(5)	(4)*14.76	(6)*14.76	(8)*14.76
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2000	1,852,948			1,803,994	7.81%								
2001	1,704,840			1,659,799	(7.90%)								
2002	1,657,946			1,614,144	(2.75%)								
Weather Adj. 2003	1,666,622	1,666,622	1,666,622	1,622,591	0.52%	1,622,591		1,622,591		$69,232,344	$23,950,361	$23,950,361	$23,950,361
Forecasted 2004	1,716,054	1,837,897	1,603,863	1,670,717	2.97%	1,789,341	10.28%	1,561,490	(3.77%)	$71,285,775	$24,660,729	$26,411,684	$23,048,473
2005	1,723,456	1,899,104	1,566,364	1,677,923	0.43%	1,848,931	3.33%	1,524,981	(2.34%)	$71,593,258	$24,767,100	$27,291,274	$22,509,586
2006	1,720,605	1,937,207	1,530,095	1,675,148	(0.17%)	1,886,027	2.01%	1,489,671	(2.32%)	$71,474,626	$24,726,129	$27,838,830	$21,988,388
2007	1,725,219	1,978,650	1,506,819	1,679,640	0.27%	1,926,376	2.14%	1,467,010	(1.52%)	$71,666,494	$24,792,435	$28,434,396	$21,653,900
2008	1,729,101	2,014,578	1,485,634	1,683,419	0.23%	1,961,354	1.82%	1,446,384	(1.41%)	$71,827,755	$24,848,222	$28,950,693	$21,349,452
2009	1,732,997	2,048,390	1,467,269	1,687,212	0.23%	1,994,273	1.68%	1,428,524	(1.23%)	$71,989,595	$24,904,210	$29,436,598	$21,085,828
2010	1,736,830	2,080,951	1,451,293	1,690,944	0.22%	2,025,973	1.59%	1,412,951	(1.09%)	$72,148,821	$24,959,293	$29,904,514	$20,855,958
2011	1,740,993	2,112,910	1,437,370	1,694,997	0.24%	2,057,089	1.54%	1,399,395	(0.96%)	$72,321,754	$25,019,117	$30,363,791	$20,655,865
2012	1,745,012	2,142,031	1,423,521	1,698,910	0.23%	2,085,440	1.38%	1,385,913	(0.96%)	$72,488,706	$25,076,873	$30,782,281	$20,456,861
2013	1,749,050	2,170,609	1,410,979	1,702,841	0.23%	2,113,263	1.33%	1,373,702	(0.88%)	$72,656,446	$25,134,901	$31,192,963	$20,276,615
2014	1,752,949	2,199,474	1,399,998	1,706,637	0.22%	2,141,365	1.33%	1,363,011	(0.78%)	$72,818,413	$25,190,932	$31,607,760	$20,118,810
2015	1,756,796	2,226,791	1,389,198	1,710,383	0.22%	2,167,961	1.24%	1,352,497	(0.77%)	$72,978,219	$25,246,216	$32,000,333	$19,963,618
2016	1,760,949	2,252,625	1,378,499	1,714,426	0.24%	2,193,112	1.16%	1,342,080	(0.77%)	$73,150,737	$25,305,897	$32,371,570	$19,809,858
2017	1,764,612	2,277,021	1,367,834	1,717,992	0.21%	2,216,864	1.08%	1,331,696	(0.77%)	$73,302,900	$25,358,537	$32,722,163	$19,656,592
2018	1,768,228	2,303,453	1,359,181	1,721,513	0.20%	2,242,598	1.16%	1,323,272	(0.63%)	$73,453,110	$25,410,501	$33,102,011	$19,532,245
2019	1,771,737	2,329,044	1,350,710	1,724,929	0.20%	2,267,512	1.11%	1,315,025	(0.62%)	$73,598,876	$25,460,927	$33,469,770	$19,410,511
2020	1,775,194	2,353,823	1,342,381	1,728,294	0.20%	2,291,637	1.06%	1,306,916	(0.62%)	$73,742,482	$25,510,606	$33,825,856	$19,290,828
2021	1,778,549	2,377,813	1,334,163	1,731,561	0.19%	2,314,993	1.02%	1,298,915	(0.61%)	$73,881,850	$25,558,820	$34,170,605	$19,172,721
2022	1,782,063	2,401,033	1,326,026	1,734,982	0.20%	2,337,599	0.98%	1,290,993	(0.61%)	$74,027,824	$25,609,318	$34,504,282	$19,055,790
2023	1,785,347	2,423,496	1,317,947	1,738,179	0.18%	2,359,469	0.94%	1,283,128	(0.61%)	$74,164,243	$25,656,511	$34,827,102	$18,939,691
2024	1,788,793			1,741,534	0.19%					$74,307,391	$25,706,032		
2025	1,792,003			1,744,659	0.18%					$74,440,736	$25,752,162		

IRRIGATION

Year	Demand Side Management: Energy Savings (MWH)	Demand Side Management: Fixed Costs Unrecovered	Revenue Recovered at Total Fixed Cost per MWH (Class & Subsidy) Rate less DSM unrecoverd costs: Base Revenue Recovered	Amount of True-Up (Base)	True-Up Percentage of Revenue Requirement (Base)	High Revenue Recovered	Amount of True-Up (High)	True-Up Percentage of Revenue Requirement (High)	Low Revenue Recovered	Amount of True-Up (Low)	True-Up Percentage of Revenue Requirement (Low)
	(14)	(14)*14.76 (15)	(11) - (15) (16)	(11) - (16) (17)	(17) / (10) (18)	(12) - (15) (19)	(11) - (19) (20)	(20)/(10) (21)	(13) - (15) (22)	(11) - (22) (23)	(23)/(10) (24)
2000											
2001											
2002											
Weather Adj. 2003											
Forecasted 2004	0	$0	$24,660,729	$0	0.00%	$26,411,684	($1,750,955)	(2.48%)	$23,048,473	$1,612,256	2.26%
2005	5,606	$82,754	$24,684,346	$82,754	0.12%	$27,208,521	($2,441,421)	(3.41%)	$22,426,833	$2,340,267	3.27%
2006	11,213	$165,507	$24,560,622	$165,507	0.23%	$27,673,323	($2,947,193)	(4.12%)	$21,822,679	$2,903,251	4.06%
2007	16,819	$248,261	$24,544,175	$248,261	0.35%	$28,186,135	($3,393,699)	(4.74%)	$21,405,639	$3,386,796	4.73%
2008	22,426	$331,015	$24,517,208	$331,015	0.46%	$28,619,679	($3,771,456)	(5.25%)	$21,018,438	$3,829,784	5.33%
2009	28,032	$413,768	$24,490,442	$413,768	0.57%	$29,022,830	($4,118,620)	(5.72%)	$20,672,059	$4,232,151	5.88%
2010	33,638	$496,522	$24,462,771	$496,522	0.69%	$29,407,992	($4,448,700)	(6.17%)	$20,359,436	$4,599,857	6.38%
2011	39,245	$579,275	$24,439,842	$579,275	0.80%	$29,784,516	($4,765,396)	(6.59%)	$20,076,590	$4,942,528	6.83%
2012	44,851	$662,029	$24,414,844	$662,029	0.91%	$30,120,252	($5,043,390)	(6.96%)	$19,794,832	$5,282,041	7.29%
2013	50,458	$744,783	$24,390,118	$744,783	1.03%	$30,448,180	($5,313,279)	(7.31%)	$19,531,832	$5,603,069	7.71%
2014	50,458	$744,783	$24,446,149	$744,783	1.02%	$30,862,977	($5,672,044)	(7.78%)	$19,374,027	$5,816,905	7.99%
2015	50,458	$744,783	$24,501,433	$744,783	1.02%	$31,255,550	($6,009,334)	(8.23%)	$19,218,835	$6,027,381	8.26%
2016	50,458	$744,783	$24,561,114	$744,783	1.02%	$31,626,795	($6,320,698)	(8.64%)	$19,065,073	$6,240,624	8.53%
2017	50,458	$744,783	$24,613,754	$744,783	1.02%	$31,977,390	($6,618,844)	(9.03%)	$18,911,809	$6,446,727	8.79%
2018	50,458	$744,783	$24,665,718	$744,783	1.01%	$32,357,228	($6,946,728)	(9.45%)	$18,787,452	$6,623,039	9.02%
2019	50,458	$744,783	$24,716,144	$744,783	1.01%	$32,724,987	($7,264,060)	(9.87%)	$18,665,728	$6,795,199	9.23%
2020	50,458	$744,783	$24,765,823	$744,783	1.01%	$33,081,074	($7,570,467)	(10.27%)	$18,546,045	$6,984,561	9.44%
2021	50,458	$744,783	$24,814,037	$744,783	1.01%	$33,425,822	($7,867,002)	(10.65%)	$18,427,938	$7,130,881	9.65%
2022	50,458	$744,783	$24,864,535	$744,783	1.01%	$33,759,500	($8,150,182)	(11.01%)	$18,311,007	$7,298,311	9.86%
2023	50,458	$744,783	$24,911,728	$744,783	1.00%	$34,082,320	($8,425,809)	(11.36%)	$18,194,908	$7,461,603	10.06%
2024											
2025											

	Totals												
	Total System			Idaho Jurisdictional Energy %							Total Fixed Cost per MWH (Class & Subsidy)		
Year	Base Case Energy (MWH)	High Growth Scenario (MWH)	High Growth Scenario (MWH)	Base Case Energy (MWH)	Base Growth Rate	High Growth Scenario (MWH)	High Growth Rate	Low Growth Scenario (MWH)	Low Growth Rate	Base Rate Revenue Requirement (less non-metered & Specials)	Base Revenue	High Revenue	Low Revenue
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2000	11,673,378			10,997,104	3.34%								
2001	11,806,034			11,112,596	1.14%								
2002	11,526,063			10,853,895	(2.37%)								
Weather Adj. 2003	11,805,036	11,805,036	11,805,036	11,114,408	2.42%	11,114,408		11,114,408		$487,811,885	$183,233,030	$183,233,030	$183,233,030
Forecasted 2004	12,146,648	12,602,115	11,740,737	11,435,579	2.89%	11,863,697	6.74%	11,053,340	(0.55%)	$501,183,204	$187,498,583	$193,212,763	$182,128,388
2005	12,480,272	13,123,849	11,876,023	11,747,198	2.75%	12,352,605	4.12%	11,179,000	1.14%	$514,126,167	$191,609,243	$199,902,028	$183,914,749
2006	12,783,841	13,594,021	12,032,169	12,030,159	2.43%	12,791,999	3.56%	11,323,576	1.29%	$525,926,716	$195,562,761	$205,867,213	$185,950,705
2007	13,094,776	14,057,758	12,212,955	12,320,126	2.43%	13,225,361	3.39%	11,491,456	1.48%	$537,961,924	$199,492,587	$211,658,327	$188,255,564
2008	13,416,062	14,520,302	12,411,512	12,620,297	2.45%	13,657,986	3.27%	11,676,530	1.61%	$550,617,416	$203,767,623	$217,670,587	$191,004,869
2009	13,724,764	14,966,152	12,606,762	12,908,510	2.30%	14,074,850	3.05%	11,858,491	1.56%	$562,705,419	$207,803,650	$223,391,894	$193,664,951
2010	14,023,818	15,395,971	12,795,007	13,187,171	2.18%	14,475,969	2.65%	12,033,398	1.47%	$574,215,261	$211,528,072	$228,654,063	$196,029,628
2011	14,320,903	15,826,418	12,989,129	13,463,981	2.12%	14,877,696	2.78%	12,213,929	1.50%	$585,634,692	$215,211,393	$233,907,286	$198,498,636
2012	14,614,932	16,244,890	13,177,079	13,737,992	2.05%	15,268,037	2.62%	12,398,623	1.43%	$596,943,093	$218,865,320	$238,967,100	$200,815,029
2013	14,913,771	16,672,010	13,375,220	14,016,491	2.04%	15,666,574	2.61%	12,573,034	1.49%	$608,442,759	$222,567,082	$244,216,933	$203,374,275
2014	15,207,907	17,093,310	13,569,586	14,290,335	1.97%	16,059,282	2.51%	12,753,672	1.44%	$619,650,701	$226,113,657	$249,246,728	$205,776,336
2015	15,499,825	17,503,849	13,756,313	14,562,033	1.92%	16,441,821	2.39%	12,927,142	1.36%	$630,744,885	$229,597,064	$254,002,485	$207,974,500
2016	15,797,410	17,929,520	13,956,824	14,839,150	1.92%	16,838,698	2.41%	13,113,740	1.44%	$642,092,725	$233,181,591	$259,103,333	$210,496,242
2017	16,098,831	18,356,923	14,158,763	15,119,754	1.91%	17,236,814	2.36%	13,301,456	1.43%	$653,570,291	$236,801,778	$264,151,805	$212,993,062
2018	16,400,864	18,793,877	14,367,535	15,400,754	1.89%	17,643,809	2.36%	13,495,632	1.46%	$665,198,822	$240,478,340	$269,255,009	$215,536,300
2019	16,707,938	19,223,256	14,570,476	15,686,880	1.85%	18,044,058	2.27%	13,684,529	1.40%	$676,792,810	$244,141,497	$274,295,823	$218,039,157
2020	17,016,040	19,657,145	14,775,943	15,973,567	1.84%	18,449,012	2.24%	13,875,534	1.40%	$688,484,229	$247,803,450	$279,297,328	$220,515,500
2021	17,325,738	20,100,795	14,988,985	16,261,626	1.82%	18,861,196	2.24%	14,073,776	1.43%	$700,182,505	$251,434,135	$284,575,204	$223,229,567
2022	17,639,829	20,552,848	15,206,004	16,553,695	1.81%	19,281,552	2.23%	14,276,288	1.43%	$712,022,678	$255,092,613	$289,602,420	$225,727,249
2023	17,952,454	20,996,638	15,416,271	16,844,409	1.77%	19,694,433	2.14%	14,470,703	1.37%	$723,806,564	$258,729,527	$294,564,442	$228,175,274
2024	18,269,070			17,138,953	1.76%					$559,274,269			
2025	18,588,717			17,438,292	1.75%					$567,959,639			

Year	Totals: Demand Side Management: Energy Savings (MWH)	Fixed Costs Unrecovered	Revenue Recovered at Total Fixed Cost per MWH (Class & Subsidy) Rate less DSM unrecoverd costs: Base Revenue Recovered	Amount of True-Up (Base)	True-Up Percentage of Revenue Requirement (Base)	High Revenue Recovered	Amount of True-Up (High)	True-Up Percentage of Revenue Requirement (High)	Low Revenue Recovered	Amount of True-Up (Low)	True-Up Percentage of Revenue Requirement (Low)
	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)
2000											
2001											
2002											
Weather Adj. 2003	0										
Forecasted 2004	0	$0	$187,496,583	$0	0.00%	$193,212,763	(5,716,180)	(1.14%)	182,128,386	5,610,340	1.12%
2005	72,883	$1,076,874	$190,592,369	$1,076,874	0.21%	$198,825,155	(7,155,912)	(1.39%)	182,837,876	9,161,976	1.78%
2006	148,570	$2,207,611	$193,355,150	$2,207,611	0.42%	$203,659,602	(8,096,840)	(1.54%)	183,743,094	12,241,222	2.33%
2007	227,059	$3,392,213	$196,100,374	$3,392,213	0.63%	$208,276,114	(8,783,526)	(1.63%)	184,863,351	15,135,856	2.81%
2008	308,352	$4,630,679	$199,136,944	$4,630,679	0.84%	$213,039,907	(9,272,284)	(1.66%)	186,374,209	17,960,121	3.27%
2009	392,448	$5,923,010	$201,880,640	$5,923,010	1.05%	$217,468,884	(9,665,234)	(1.72%)	187,741,942	20,724,524	3.68%
2010	482,150	$7,323,068	$204,205,004	$7,323,068	1.28%	$221,330,995	(9,802,923)	(1.71%)	188,706,560	23,562,978	4.10%
2011	574,656	$8,776,991	$206,434,402	$8,776,991	1.50%	$225,160,294	(9,948,901)	(1.70%)	189,721,645	26,309,396	4.49%
2012	669,965	$10,284,778	$208,570,541	$10,284,778	1.72%	$228,882,321	(9,827,002)	(1.65%)	190,530,251	29,223,709	4.90%
2013	767,516	$11,835,657	$210,731,425	$11,835,657	1.95%	$232,381,277	(9,814,195)	(1.61%)	191,538,618	32,004,668	5.26%
2014	767,516	$11,835,657	$214,278,200	$11,835,657	1.91%	$237,411,071	(11,297,214)	(1.82%)	193,940,679	33,230,445	5.36%
2015	767,516	$11,835,657	$217,761,407	$11,835,657	1.88%	$242,168,829	(12,509,765)	(1.99%)	196,138,843	34,591,949	5.48%
2016	767,516	$11,835,657	$221,345,934	$11,835,657	1.84%	$247,267,676	(14,086,085)	(2.19%)	198,660,585	35,732,717	5.57%
2017	767,516	$11,835,657	$224,968,121	$11,835,657	1.81%	$252,316,148	(15,514,370)	(2.37%)	201,157,405	36,942,036	5.65%
2018	767,516	$11,835,657	$228,642,683	$11,835,657	1.78%	$257,419,352	(16,941,012)	(2.55%)	203,700,644	38,163,728	5.74%
2019	767,516	$11,835,657	$232,305,840	$11,835,657	1.75%	$262,460,167	(18,318,670)	(2.71%)	206,203,500	39,403,361	5.82%
2020	767,516	$11,835,657	$235,967,794	$11,835,657	1.72%	$267,461,671	(19,658,221)	(2.90%)	208,679,843	40,676,509	5.91%
2021	767,516	$11,835,657	$239,598,478	$11,835,657	1.69%	$272,739,547	(21,305,412)	(3.04%)	211,393,910	41,678,266	5.95%
2022	767,516	$11,835,657	$243,257,156	$11,835,657	1.66%	$277,768,764	(22,873,950)	(3.18%)	213,891,592	42,941,217	6.03%
2023	767,516	$11,835,657	$246,693,870	$11,835,657	1.64%	$282,728,785	(23,999,258)	(3.32%)	216,339,517	44,219,908	6.11%
2024											
2025											

APPENDIX 9—FIXED COST LOST REVENUE PER MWH BY CUSTOMER CLASS

Fixed Cost Lost Revenue per MWh by Customer Class					
		Base Rate Components ($/MWh)			
		Residential	**Commercial***	**Irrigation**	**Industrial****
Total Base Energy Cost per MWH	(1)	$51.90	$29.32	$32.57	$21.45
Variable Cost per MWH - *Class*	(2)	$20.69	$20.21	$23.53	$18.41
Variable Cost per MWH - *Subsidy*	(3)	$1.08	$0.81	($5.72)	$0.60
Fixed Cost per MWH - *Class*	(4)	$28.76	$7.25	$22.09	$1.67
Fixed Cost per MWH - *Subsidy*	(5)	$1.38	$1.04	($7.33)	$0.77
Total Fixed Cost per MWH (Class & Subsidy)	(6)	$30.14	$8.29	$14.76	$2.44

(*) Commercial rate is a weighted avg. of schedules 07 & 09 S,P, & T based on energy use.

(**) Industrial rate is a wghtd. avg. of schedule 19 S, P & T based on energy use.

APPENDIX 10—FLIP CHARTS REGARDING MIKE YOUNGBLOOD'S PRESENTATION

Rate Impacts by Class

NWPCC/weather adjusted with true-up

Residential

1) If energy sales faster than forecast and DSM = growth, brings back to base.

   (Ralph's perspective) It is not trying to reward company for increased growth—provides for status quo in rate case

2) For DSM, % class increase still relatively small on an annual basis in short term. Regular rate case would adjust recovery so that effect in long term wouldn't be as high as modeled.

3) With increase kWh use (and increased number of customers), may result in refund to customers plus additional cost for more facility investment.

Results with True-up

1) In high growth, company may be refunding customers and investing in capital/infrastructure.

2) Trends of true-up effects similar between rate classes.

Customer Count Model

(Revenue side only)—Recoupling to revenue per customer

1) Number of customers doesn't affect recover (when use per customer does not change)

2) For high, refund in first few years while use is higher, then positive return to company after first few years.

3) For low case, collecting more than DSM

4) 1.2% over time period in fixed cost recovery

5) For industrial customers, change in number of customers has greater effect (irrigation customers are problematic)—served better by forecast energy

6) Residential, small group—served better by customer count

APPENDIX 11— MODEL OF RATE IMPACTS BY CLASS UNDER CUSTOMER COUNTS

RESIDENTIAL

This is a dynamic model and so the values change. The numbers here represent just one scenario based upon the input assumptions.

Constants:

1*	$30.14	Total Fixed Cost per MWH (Class & Subsidy)
2*	$232,325,720	Class Revenue Requirement
3*	$378.23	Fixed Cost Recovery per Customer
4*	3	DSM Savings Assumptions: (1) DSM Savings Assumptions in 2004 IRP (2) Enhanced Residential and Commercial Numbers (Mike Rufo's Analysis) (3) Northwest Power & Conservation Council's DSM Assumptions
5*	1.0%	Percentage Growth in Customer Count
6*	0.0%	Change in Avg. Use per Cust. (Base)
7*	1.0%	Percentage above Base (High)
8*	(1.0%)	Percentage below Base (Low)
9*	1	Compounded? (0=No, 1=Yes)

Year	Base Case Energy (MWH)	Base Case Fixed Cost Recovery	Number of Customers	Fixed Cost Recovery per Customer	Actual Customer Count		Allowed Fixed Cost Recovery Per Customer Count		Energy Savings (MWH)	Fixed Costs Unrecovered		BASE: Avg. Use / Cust. (Base)	BASE: Actual Fixed Cost Recovery Per MWH (Constant Use/Cust)	BASE: Base Case Fixed Cost Revenue Recovered	BASE: Amount of True-Up (Base)	BASE: Percent of Class Revenue Requirement	
(1)	(2)	(3) (2) X 5*	(4)	(5) (3) / (4)	(6) (4) X 5*	(7)	(8) (6) X (5)	(9)	(10)	(11) (10) X 1*	(12)	(13) (13) X 6*	(14) (13) X (6) X 1*	(15) (14) - (11)	(16) (8) - (15)	(17) (16) / 2*	(18)
2003	**4,219,174**	**$127,161,141**	**336,204**	**$378.23**								**12,549**					
2004					339,566		$128,432,753		0	$0		12,549	$128,432,753	$128,432,753	$0	0.00%	
2005					342,962		$129,717,080		25,229	$760,368		12,549	$129,717,080	$128,956,713	$760,368	0.33%	
2006					346,391		$131,014,251		51,859	$1,562,978		12,549	$131,014,251	$129,451,273	$1,562,978	0.67%	
2007					349,855		$132,324,394		79,891	$2,407,831		12,549	$132,324,394	$129,916,563	$2,407,831	1.04%	
2008					353,354		$133,647,637		109,325	$3,294,926		12,549	$133,647,637	$130,352,711	$3,294,926	1.42%	
2009					356,887		$134,984,114		140,150	$4,224,265		12,549	$134,984,114	$130,759,849	$4,224,265	1.82%	
2010					360,456		$136,333,955		173,708	$5,238,088		12,549	$136,333,955	$131,096,857	$5,238,088	2.25%	
2011					364,061		$137,697,295		208,838	$6,294,154		12,549	$137,697,295	$131,403,140	$6,294,154	2.71%	
2012					367,701		$139,074,267		246,280	$7,392,463		12,549	$139,074,267	$131,681,805	$7,392,463	3.18%	
2013					371,378		$140,465,010		282,843	$8,524,566		12,549	$140,465,010	$131,940,444	$8,524,566	3.67%	
2014					375,092		$141,869,660		282,843	$8,524,566		12,549	$141,869,660	$133,345,094	$8,524,566	3.67%	
2015					378,843		$143,288,357		282,843	$8,524,566		12,549	$143,288,357	$134,763,791	$8,524,566	3.67%	
2016					382,631		$144,721,240		282,843	$8,524,566		12,549	$144,721,240	$136,196,675	$8,524,566	3.67%	
2017					386,458		$146,168,453		282,843	$8,524,566		12,549	$146,168,453	$137,643,887	$8,524,566	3.67%	
2018					390,322		$147,630,137		282,843	$8,524,566		12,549	$147,630,137	$139,105,572	$8,524,566	3.67%	
2019					394,226		$149,106,439		282,843	$8,524,566		12,549	$149,106,439	$140,581,873	$8,524,566	3.67%	
2020					398,168		$150,597,503		282,843	$8,524,566		12,549	$150,597,503	$142,072,937	$8,524,566	3.67%	
2021					402,149		$152,103,478		282,843	$8,524,566		12,549	$152,103,478	$143,578,912	$8,524,566	3.67%	
2022					406,171		$153,624,513		282,843	$8,524,566		12,549	$153,624,513	$145,099,947	$8,524,566	3.67%	
2023					410,233		$155,160,758		282,843	$8,524,566		12,549	$155,160,758	$146,636,192	$8,524,566	3.67%	

RESIDENTIAL

	HIGH						LOW				
Year	Avg. Use / Cust. (High)	Percent Increase in Average Use per Customer	High Case Fixed Cost Revenue Recovered	Amount of True-Up (High)	Percent of Class Revenue Requirement (High)		Avg. Use / Cust. (Low)	Percent Decrease in Average Use per Customer	Low Case Fixed Cost Revenue Recovered	Amount of True-Up (Low)	Percent of Class Revenue Requirement (Low)
(1)	(19)	(20)	(21)	(22)	(23)	(24)	(25)	(26)	(27)	(28)	(29)
	(19) X (5"+7")	(19) X (6) X 1"	(20) - (11)	(8) - (21)	(22) / 2"		(25) X (5"+8")	(25) X (6) X 1"	(26) - (11)	(8) - (27)	(28) / 2"
2003	**12,549**						**12,549**				
2004	12,675	$129,717,080	$129,717,080	($1,284,328)	(0.55%)		12,424	$127,148,425	$127,148,425	$1,284,328	0.55%
2005	12,802	$132,324,394	$131,564,026	($1,846,945)	(0.79%)		12,300	$127,135,710	$126,375,343	$3,341,738	1.44%
2006	12,930	$134,984,114	$133,421,136	($2,406,885)	(1.04%)		12,177	$127,122,997	$125,560,019	$5,454,232	2.35%
2007	13,059	$137,697,295	$135,289,464	($2,965,070)	(1.28%)		12,055	$127,110,284	$124,702,454	$7,621,940	3.28%
2008	13,190	$140,465,010	$137,170,084	($3,522,446)	(1.52%)		11,934	$127,097,573	$123,802,647	$9,844,990	4.24%
2009	13,321	$143,288,357	$139,064,092	($4,079,978)	(1.76%)		11,815	$127,084,864	$122,860,599	$12,123,515	5.22%
2010	13,455	$146,168,453	$140,930,365	($4,595,410)	(1.98%)		11,697	$127,072,155	$121,834,067	$14,499,888	6.24%
2011	13,589	$149,106,439	$142,812,285	($5,114,990)	(2.20%)		11,580	$127,059,448	$120,765,294	$16,932,001	7.29%
2012	13,725	$152,103,478	$144,711,015	($5,636,748)	(2.43%)		11,464	$127,046,742	$119,654,279	$19,419,988	8.36%
2013	13,862	$155,160,758	$146,636,192	($6,171,182)	(2.66%)		11,349	$127,034,037	$118,509,471	$21,955,539	9.45%
2014	14,001	$158,279,489	$149,754,923	($7,885,263)	(3.39%)		11,236	$127,021,334	$118,496,768	$23,372,892	10.06%
2015	14,141	$161,460,907	$152,936,341	($9,647,984)	(4.15%)		11,124	$127,008,632	$118,484,066	$24,804,291	10.68%
2016	14,282	$164,706,271	$156,181,705	($11,460,465)	(4.93%)		11,012	$126,995,931	$118,471,365	$26,249,875	11.30%
2017	14,425	$168,016,867	$159,492,301	($13,323,849)	(5.73%)		10,902	$126,983,231	$118,458,665	$27,709,787	11.93%
2018	14,570	$171,394,006	$162,869,440	($15,239,303)	(6.56%)		10,793	$126,970,533	$118,445,967	$29,184,170	12.56%
2019	14,715	$174,839,026	$166,314,460	($17,208,021)	(7.41%)		10,685	$126,957,836	$118,433,270	$30,673,169	13.20%
2020	14,862	$178,353,290	$169,828,724	($19,231,221)	(8.28%)		10,578	$126,945,140	$118,420,574	$32,176,929	13.85%
2021	15,011	$181,938,191	$173,413,626	($21,310,147)	(9.17%)		10,473	$126,932,446	$118,407,880	$33,695,598	14.50%
2022	15,161	$185,595,149	$177,070,583	($23,446,070)	(10.09%)		10,368	$126,919,752	$118,395,187	$35,229,326	15.16%
2023	15,313	$189,325,612	$180,801,046	($25,640,288)	(11.04%)		10,264	$126,907,060	$118,382,495	$38,778,263	15.83%

COMMERCIAL

This is a dynamic model and so the values change. The numbers here represent just one scenario based upon the input assumptions.

Constants:

1*	$8.29	Total Fixed Cost per MWH (Class & Subsidy)
2*	$129,540,066	Class Revenue Requirement
3*	$535.30	Fixed Cost Recovery per Customer
4*	3	DSM Savings Assumptions: (1) DSM Savings Assumptions in 2004 IRP (2) Enhanced Residential and Commercial Numbers (Mike Rufo's Analysis) (3) Northwest Power & Conservation Council's DSM Assumptions
5*	1.0%	Percentage Growth in Customer Count
6*	0.0%	Change in Avg. Use per Cust. (Base)
7*	1.0%	Percentage above Base (High)
8*	(1.0%)	Percentage below Base (Low)
9*	1	Compounded? (0=No, 1=Yes)

Year (1)	Base Case Energy (MWH) (2)	Base Case Fixed Cost Recovery (3) (2) X 1*	Number of Customers (4)	Fixed Cost Recovery per Customer (5) (3) / (4)	Actual Customer Count (6) (4) X 5*	(7)	Allowed Fixed Cost Recovery Per Customer Count (8) (6) X (5)	(9)	Energy Savings (MWH) (10)	Fixed Costs Unrecovered (11) (10) X 1*	(12)	BASE: Avg. Use / Cust. (Base) (13) (13) X 6*	BASE: Actual Fixed Cost Recovery Per MWH (Constant Use/Cust) (14) (13) X (6) X 1*	BASE: Base Case Fixed Cost Revenue Recovered (15) (14) - (11)	BASE: Amount of True-Up (Base) (16) (8) - (15)	BASE: Percent of Class Revenue Requirement (17) (16) / 2*	(18)
2003	3,291,982	$27,295,897	50,992	$535.30								64,559					
2004					51,501		$27,568,850		0	$0		64,559	$27,568,850	$27,568,850	$0	0.00%	
2005					52,016		$27,844,545		22,420	$185,945		64,559	$27,844,545	$27,658,600	$185,945	0.14%	
2006					52,537		$28,122,990		46,253	$383,511		64,559	$28,122,990	$27,739,479	$383,511	0.30%	
2007					53,062		$28,404,220		71,482	$592,699		64,559	$28,404,220	$27,811,521	$592,699	0.46%	
2008					53,593		$28,688,262		98,112	$813,508		64,559	$28,688,262	$27,874,754	$813,508	0.63%	
2009					54,129		$28,975,145		126,144	$1,045,939		64,559	$28,975,145	$27,929,205	$1,045,939	0.81%	
2010					54,670		$29,264,896		156,979	$1,301,614		64,559	$29,264,890	$27,963,283	$1,301,614	1.00%	
2011					55,217		$29,557,545		189,216	$1,568,909		64,559	$29,557,545	$27,988,636	$1,568,909	1.21%	
2012					55,769		$29,853,121		222,854	$1,847,826		64,559	$29,853,121	$28,005,294	$1,847,826	1.43%	
2013					56,326		$30,151,652		257,614	$2,136,041		64,559	$30,151,652	$28,015,611	$2,136,041	1.65%	
2014					56,890		$30,453,168		257,614	$2,136,041		64,559	$30,453,168	$28,317,128	$2,136,041	1.65%	
2015					57,459		$30,757,700		257,614	$2,136,041		64,559	$30,757,700	$28,621,659	$2,136,041	1.65%	
2016					58,033		$31,065,277		257,614	$2,136,041		64,559	$31,065,277	$28,929,236	$2,136,041	1.65%	
2017					58,613		$31,375,930		257,614	$2,136,041		64,559	$31,375,930	$29,239,889	$2,136,041	1.65%	
2018					59,200		$31,689,689		257,614	$2,136,041		64,559	$31,689,689	$29,553,648	$2,136,041	1.65%	
2019					59,792		$32,006,586		257,614	$2,136,041		64,559	$32,006,586	$29,870,545	$2,136,041	1.65%	
2020					60,390		$32,326,652		257,614	$2,136,041		64,559	$32,326,652	$30,190,611	$2,136,041	1.65%	
2021					60,993		$32,649,919		257,614	$2,136,041		64,559	$32,649,919	$30,513,878	$2,136,041	1.65%	
2022					61,603		$32,976,418		257,614	$2,136,041		64,559	$32,976,418	$30,840,377	$2,136,041	1.65%	
2023					62,219		$33,306,182		257,614	$2,136,041		64,559	$33,306,182	$31,170,141	$2,136,041	1.65%	

COMMERCIAL

	HIGH						LOW				
Year	Avg. Use / Cust. (High)	Percent Increase in Average Use per Customer	High Case Fixed Cost Revenue Recovered	Amount of True-Up (High)	Percent of Class Revenue Requirement (High)		Avg. Use / Cust. (Low)	Percent Decrease in Average Use per Customer	Low Case Fixed Cost Revenue Recovered	Amount of True-Up (Low)	Percent of Class Revenue Requirement (Low)
(1)	(19) (19) X (6"+7")	(20) (19) X (6) X 1"	(21) (20) - (11)	(22) (8) - (21)	(23) (22) / 2"	(24)	(25) (25) X (6"+8")	(26) (25) X (6) X 1"	(27) (26) - (11)	(28) (8) - (27)	(29) (28) / 2"
2003	**64,559**						**64,559**				
2004	65,205	$27,844,545	$27,844,545	($275,689)	(0.21%)		63,914	$27,293,168	$27,293,168	$275,689	0.21%
2005	65,857	$28,404,220	$28,218,275	($373,731)	(0.29%)		63,275	$27,290,438	$27,104,493	$740,051	0.57%
2006	66,516	$28,975,145	$28,591,634	($468,644)	(0.36%)		62,642	$27,287,709	$26,904,198	$1,218,792	0.94%
2007	67,181	$29,557,545	$28,964,846	($560,626)	(0.43%)		62,015	$27,284,980	$26,692,281	$1,711,939	1.32%
2008	67,853	$30,151,652	$29,338,143	($649,681)	(0.50%)		61,395	$27,282,252	$26,468,743	$2,219,519	1.71%
2009	68,531	$30,757,700	$29,711,761	($736,616)	(0.57%)		60,781	$27,279,524	$26,233,584	$2,741,561	2.12%
2010	69,216	$31,375,930	$30,074,316	($809,420)	(0.62%)		60,174	$27,276,796	$25,975,182	$3,289,714	2.54%
2011	69,909	$32,006,586	$30,437,677	($880,132)	(0.68%)		59,572	$27,274,068	$25,705,159	$3,852,398	2.97%
2012	70,608	$32,649,919	$30,802,092	($948,971)	(0.73%)		58,976	$27,271,341	$25,423,514	$4,429,606	3.42%
2013	71,314	$33,306,182	$31,170,141	($1,018,489)	(0.79%)		58,386	$27,268,614	$25,132,573	$5,019,079	3.87%
2014	72,027	$33,975,636	$31,839,595	($1,386,427)	(1.07%)		57,802	$27,265,887	$25,129,846	$5,323,323	4.11%
2015	72,747	$34,658,546	$32,522,506	($1,764,806)	(1.36%)		57,224	$27,263,160	$25,127,119	$5,630,581	4.35%
2016	73,475	$35,355,183	$33,219,142	($2,153,865)	(1.66%)		56,652	$27,260,434	$25,124,393	$5,940,884	4.59%
2017	74,209	$36,065,822	$33,929,782	($2,553,852)	(1.97%)		56,086	$27,257,708	$25,121,667	$6,254,263	4.83%
2018	74,951	$36,790,745	$34,654,705	($2,965,015)	(2.29%)		55,525	$27,254,982	$25,118,941	$6,570,748	5.07%
2019	75,701	$37,530,239	$35,394,199	($3,387,612)	(2.62%)		54,970	$27,252,256	$25,116,216	$6,890,370	5.32%
2020	76,458	$38,284,597	$36,148,556	($3,821,904)	(2.95%)		54,420	$27,249,531	$25,113,490	$7,213,162	5.57%
2021	77,222	$39,054,118	$36,918,077	($4,268,158)	(3.29%)		53,876	$27,246,806	$25,110,765	$7,539,153	5.82%
2022	77,995	$39,839,105	$37,703,065	($4,726,647)	(3.65%)		53,337	$27,244,082	$25,108,041	$7,868,377	6.07%
2023	78,775	$40,639,871	$38,503,831	($5,197,649)	(4.01%)		52,804	$27,241,357	$25,105,316	$8,200,865	6.33%

INDUSTRIAL

This is a dynamic model and so the values change. The numbers here represent just one scenario based upon the input assumptions.

Constants:

1* $2.44 Total Fixed Cost per MWH (Class & Subsidy)
2* $66,713,736 Class Revenue Requirement
3* $46,400.29 Fixed Cost Recovery per Customer
4* 3 DSM Savings Assumptions:
(1) DSM Savings Assumptions in 2004 IRP
(2) Enhanced Residential and Commercial Numbers (Mike Rufo's Analysis)
(3) Northwest Power & Conservation Council's DSM Assumptions
5* 1.0% Percentage Growth in Customer Count
6* 0.0% Change in Avg. Use per Cust. (Base)
7* 1.0% Percentage above Base (High)
8* (1.0%) Percentage below Base (Low)
9* 1 Compounded? (0=No, 1=Yes)

												BASE					
Year	Base Case Energy (MWH)	Base Case Fixed Cost Recovery	Number of Customers	Fixed Cost Recovery per Customer	Actual Customer Count		Allowed Fixed Cost Recovery Per Customer Count		Energy Savings (MWH)	Fixed Costs Unrecovered		Avg. Use / Cust. (Base)	Actual Fixed Cost Recovery Per MWH (Constant Use/Cust)	Base Case Fixed Cost Revenue Recovered	Amount of True-Up (Base)	Percent of Class Revenue Requirement	
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
		(2) X 1*		(3) / (4)	(4) X 5*		(6) X (5)			(10) X 1*		(13) X 6*	(13) X (6) X 1*	(14) - (11)	(8) - (15)	(16) / 2*	
2003	**1,980,662**	**$4,826,631**	**104**	**$46,400.29**								**19,044,825**					
2004					105		$4,873,887		0	$0		19,044,825	$4,873,887	$4,873,887	$0	0.00%	
2005					106		$4,922,626		19,622	$47,807		19,044,825	$4,922,626	$4,874,818	$47,807	0.08%	
2006					107		$4,971,852		39,245	$95,615		19,044,825	$4,971,852	$4,876,237	$95,615	0.17%	
2007					108		$5,021,571		58,867	$143,422		19,044,825	$5,021,571	$4,878,149	$143,422	0.25%	
2008					109		$5,071,786		78,490	$191,230		19,044,825	$5,071,786	$4,880,556	$191,230	0.34%	
2009					110		$5,122,504		98,112	$239,037		19,044,825	$5,122,504	$4,883,467	$239,037	0.42%	
2010					112		$5,173,729		117,734	$286,845		19,044,825	$5,173,729	$4,886,884	$286,845	0.51%	
2011					113		$5,225,466		137,357	$334,652		19,044,825	$5,225,466	$4,890,814	$334,652	0.59%	
2012					114		$5,277,721		156,979	$382,460		19,044,825	$5,277,721	$4,895,261	$382,460	0.67%	
2013					115		$5,330,498		176,602	$430,267		19,044,825	$5,330,498	$4,900,231	$430,267	0.76%	
2014					116		$5,383,803		176,602	$430,267		19,044,825	$5,383,803	$4,953,536	$430,267	0.76%	
2015					117		$5,437,641		176,602	$430,267		19,044,825	$5,437,641	$5,007,374	$430,267	0.76%	
2016					118		$5,492,018		176,602	$430,267		19,044,825	$5,492,018	$5,061,750	$430,267	0.76%	
2017					120		$5,546,938		176,602	$430,267		19,044,825	$5,546,938	$5,116,671	$430,267	0.76%	
2018					121		$5,602,407		176,602	$430,267		19,044,825	$5,602,407	$5,172,140	$430,267	0.76%	
2019					122		$5,658,431		176,602	$430,267		19,044,825	$5,658,431	$5,228,164	$430,267	0.76%	
2020					123		$5,715,016		176,602	$430,267		19,044,825	$5,715,016	$5,284,749	$430,267	0.76%	
2021					124		$5,772,166		176,602	$430,267		19,044,825	$5,772,166	$5,341,899	$430,267	0.76%	
2022					126		$5,829,888		176,602	$430,267		19,044,825	$5,829,888	$5,399,620	$430,267	0.76%	
2023					127		$5,888,186		176,602	$430,267		19,044,825	$5,888,186	$5,457,919	$430,267	0.76%	

INDUSTRIAL

	HIGH						LOW				
Year	Avg. Use / Cust. (High)	Percent Increase in Average Use per Customer	High Case Fixed Cost Revenue Recovered	Amount of True-Up (High)	Percent of Class Revenue Requirement (High)		Avg. Use / Cust. (Low)	Percent Decrease in Average Use per Customer	Low Case Fixed Cost Revenue Recovered	Amount of True-Up (Low)	Percent of Class Revenue Requirement (Low)
(1)	(19)	(20)	(21)	(22)	(23)	(24)	(25)	(26)	(27)	(28)	(29)
	(19) X (6"+7")	(19) X (6) X 1"	(20) - (11)	(8) - (21)	(22) / 2"		(25) X (6"+8")	(25) X (6) X 1"	(26) - (11)	(8) - (27)	(28) / 2"
2003	**19,044,825**						**19,044,825**				
2004	19,235,273	$4,922,626	$4,922,626	($48,739)	(0.09%)		18,854,376	$4,825,149	$4,825,149	$48,739	0.09%
2005	19,427,625	$5,021,571	$4,973,763	($51,137)	(0.09%)		18,665,832	$4,824,666	$4,776,858	$145,768	0.26%
2006	19,621,902	$5,122,504	$5,026,889	($55,037)	(0.10%)		18,479,174	$4,824,183	$4,728,568	$243,284	0.43%
2007	19,818,121	$5,225,466	$5,082,044	($60,473)	(0.11%)		18,294,382	$4,823,701	$4,680,278	$341,292	0.60%
2008	20,016,302	$5,330,498	$5,139,268	($67,482)	(0.12%)		18,111,439	$4,823,218	$4,631,988	$439,798	0.78%
2009	20,216,465	$5,437,641	$5,198,604	($76,100)	(0.13%)		17,930,324	$4,822,736	$4,583,699	$538,806	0.95%
2010	20,418,630	$5,548,938	$5,260,093	($86,364)	(0.15%)		17,751,021	$4,822,254	$4,535,409	$638,320	1.13%
2011	20,622,816	$5,658,431	$5,323,779	($98,313)	(0.17%)		17,573,511	$4,821,771	$4,487,119	$738,347	1.30%
2012	20,829,044	$5,772,166	$5,389,706	($111,985)	(0.20%)		17,397,776	$4,821,289	$4,438,829	$838,892	1.48%
2013	21,037,335	$5,888,186	$5,457,919	($127,421)	(0.22%)		17,223,798	$4,820,807	$4,390,540	$939,959	1.66%
2014	21,247,708	$6,006,539	$5,576,272	($192,468)	(0.34%)		17,051,560	$4,820,325	$4,390,058	$993,748	1.75%
2015	21,460,185	$6,127,270	$5,697,003	($259,362)	(0.46%)		16,881,044	$4,819,843	$4,389,576	$1,048,066	1.85%
2016	21,674,787	$6,250,429	$5,820,161	($328,143)	(0.58%)		16,712,234	$4,819,361	$4,389,094	$1,102,924	1.94%
2017	21,891,535	$6,376,062	$5,945,795	($398,857)	(0.70%)		16,545,112	$4,816,879	$4,368,612	$1,158,326	2.04%
2018	22,110,450	$6,504,221	$6,073,954	($471,546)	(0.83%)		16,379,660	$4,818,397	$4,388,130	$1,214,277	2.14%
2019	22,331,555	$6,634,956	$6,204,688	($546,257)	(0.96%)		16,215,864	$4,817,915	$4,387,648	$1,270,783	2.24%
2020	22,554,870	$6,768,318	$6,338,051	($623,035)	(1.10%)		16,053,705	$4,817,434	$4,387,166	$1,327,849	2.34%
2021	22,780,419	$6,904,362	$6,474,094	($701,926)	(1.24%)		15,893,168	$4,816,952	$4,366,685	$1,385,481	2.44%
2022	23,008,223	$7,043,139	$6,612,872	($782,984)	(1.38%)		15,734,236	$4,816,470	$4,386,203	$1,443,685	2.55%
2023	23,238,305	$7,184,706	$6,754,439	($866,253)	(1.53%)		15,576,894	$4,815,989	$4,385,721	$1,502,465	2.65%

IRRIGATION

This is a dynamic model and so the values change. The numbers here represent just one scenario based upon the input assumptions.

Constants:

1*	$14.76	Total Fixed Cost per MWH (Class & Subsidy)
2*	$69,232,344	Class Revenue Requirement
3*	$1,636.62	Fixed Cost Recovery per Customer
4*	3	DSM Savings Assumptions: (1) DSM Savings Assumptions in 2004 IRP; (2) Enhanced Residential and Commercial Numbers (Mike Rufo's Analysis); (3) Northwest Power & Conservation Council's DSM Assumptions
5*	1.0%	Percentage Growth in Customer Count
6*	0.0%	Change in Avg. Use per Cust. (Base)
7*	1.0%	Percentage above Base (High)
8*	(1.0%)	Percentage below Base (Low)
9*	1	Compounded? (0=No, 1=Yes)

Year	Base Case Energy (MWH)	Base Case Fixed Cost Recovery	Number of Customers	Fixed Cost Recovery per Customer	Actual Customer Count		Allowed Fixed Cost Recovery Per Customer Count		Energy Savings (MWH)	Fixed Costs Unrecovered		BASE: Avg. Use / Cust. (Base)	BASE: Actual Fixed Cost Recovery Per MWH (Constant Use/Cust)	BASE: Base Case Fixed Cost Revenue Recovered	BASE: Amount of True-Up (Base)	BASE: Percent of Class Revenue Requirement	
(1)	(2)	(3) (2) X 1*	(4)	(5) (3) / (4)	(6) (4) X 5*	(7)	(8) (6) X (5)	(9)	(10)	(11) (10) X 1*	(12)	(13) (13) X 6*	(14) (13) X (6) X 1*	(15) (14) - (11)	(16) (8) - (15)	(17) (16) / 2*	(18)
2003	**1,622,681**	**$23,960,361**	**14,643**	**$1,636.42**								**110,810**					
2004					14,789		$24,189,865		0	$0		110,810	$24,189,865	$24,189,865	$0	0.00%	
2005					14,937		$24,431,764		5,600	$82,754		110,810	$24,431,764	$24,349,010	$82,754	0.12%	
2006					15,087		$24,676,081		11,213	$165,507		110,810	$24,676,081	$24,510,574	$165,507	0.24%	
2007					15,238		$24,922,842		16,819	$248,261		110,810	$24,922,842	$24,674,581	$248,261	0.36%	
2008					15,390		$25,172,070		22,426	$331,015		110,810	$25,172,070	$24,841,055	$331,015	0.48%	
2009					15,544		$25,423,791		28,032	$413,768		110,810	$25,423,791	$25,010,023	$413,768	0.60%	
2010					15,699		$25,678,029		33,638	$496,522		110,810	$25,678,029	$25,181,507	$496,522	0.72%	
2011					15,856		$25,934,809		39,245	$579,275		110,810	$25,934,809	$25,355,534	$579,275	0.84%	
2012					16,015		$26,194,157		44,851	$662,029		110,810	$26,194,157	$25,532,128	$662,029	0.96%	
2013					16,175		$26,456,099		50,458	$744,783		110,810	$26,456,099	$25,711,316	$744,783	1.08%	
2014					16,337		$26,720,660		50,458	$744,783		110,810	$26,720,660	$25,975,877	$744,783	1.08%	
2015					16,500		$26,987,867		50,458	$744,783		110,810	$26,987,867	$26,243,084	$744,783	1.08%	
2016					16,665		$27,257,745		50,458	$744,783		110,810	$27,257,745	$26,512,962	$744,783	1.08%	
2017					16,832		$27,530,323		50,458	$744,783		110,810	$27,530,323	$26,785,540	$744,783	1.08%	
2018					17,000		$27,805,626		50,458	$744,783		110,810	$27,805,626	$27,060,843	$744,783	1.08%	
2019					17,170		$28,083,682		50,458	$744,783		110,810	$28,083,682	$27,338,899	$744,783	1.08%	
2020					17,342		$28,364,519		50,458	$744,783		110,810	$28,364,519	$27,619,736	$744,783	1.08%	
2021					17,515		$28,648,164		50,458	$744,783		110,810	$28,648,164	$27,903,381	$744,783	1.08%	
2022					17,690		$28,934,646		50,458	$744,783		110,810	$28,934,646	$28,189,863	$744,783	1.08%	
2023					17,867		$29,223,992		50,458	$744,783		110,810	$29,223,992	$28,479,210	$744,783	1.08%	

IRRIGATION

	HIGH						LOW				
Year	Avg. Use / Cust. (High)	Percent Increase in Average Use per Customer	High Case Fixed Cost Revenue Recovered	Amount of True-Up (High)	Percent of Class Revenue Requirement (High)		Avg. Use / Cust. (Low)	Percent Decrease in Average Use per Customer	Low Case Fixed Cost Revenue Recovered	Amount of True-Up (Low)	Percent of Class Revenue Requirement (Low)
(1)	(19)	(20)	(21)	(22)	(23)	(24)	(25)	(26)	(27)	(28)	(29)
	(19) X (6"+7")	(19) X (6) X 1"	(20) - (11)	(8) - (21)	(22) / 2"		(25) X (6"+8")	(25) X (6) X 1"	(26) - (11)	(8) - (27)	(28) / 2"
2003	**110,810**						**110,810**				
2004	111,918	$24,431,764	$24,431,764	($241,699)	(0.35%)		109,702	$23,947,966	$23,947,966	$241,699	0.35%
2005	113,037	$24,922,842	$24,840,088	($408,325)	(0.59%)		108,605	$23,945,571	$23,862,818	$563,946	0.82%
2006	114,168	$25,423,791	$25,258,284	($582,203)	(0.84%)		107,519	$23,943,177	$23,777,670	$898,412	1.30%
2007	115,309	$25,934,909	$25,686,548	($763,708)	(1.10%)		106,444	$23,940,783	$23,692,522	$1,230,320	1.78%
2008	116,462	$26,456,099	$26,125,084	($953,014)	(1.38%)		105,379	$23,938,389	$23,607,374	$1,564,696	2.26%
2009	117,627	$26,987,867	$26,574,096	($1,150,307)	(1.66%)		104,325	$23,935,995	$23,522,226	$1,901,565	2.75%
2010	118,803	$27,530,323	$27,033,801	($1,355,772)	(1.96%)		103,282	$23,933,601	$23,437,079	$2,240,950	3.24%
2011	119,991	$28,083,682	$27,504,407	($1,569,597)	(2.27%)		102,249	$23,931,208	$23,351,932	$2,582,877	3.73%
2012	121,191	$28,648,164	$27,966,135	($1,791,976)	(2.59%)		101,227	$23,928,815	$23,266,785	$2,927,372	4.23%
2013	122,403	$29,223,992	$28,479,210	($2,023,111)	(2.92%)		100,215	$23,926,422	$23,181,639	$3,274,460	4.73%
2014	123,627	$29,811,395	$29,066,612	($2,345,952)	(3.39%)		99,212	$23,924,029	$23,179,246	$3,541,414	5.12%
2015	124,863	$30,410,604	$29,665,821	($2,677,954)	(3.87%)		98,220	$23,921,637	$23,176,854	$3,811,013	5.50%
2016	126,112	$31,021,857	$30,277,074	($3,019,329)	(4.36%)		97,238	$23,919,244	$23,174,462	$4,083,284	5.90%
2017	127,373	$31,645,396	$30,900,613	($3,370,291)	(4.87%)		96,265	$23,916,853	$23,172,070	$4,358,253	6.30%
2018	128,647	$32,281,468	$31,536,686	($3,731,050)	(5.39%)		95,303	$23,914,461	$23,169,678	$4,635,948	6.70%
2019	129,933	$32,930,326	$32,185,543	($4,101,861)	(5.92%)		94,350	$23,912,069	$23,167,287	$4,918,398	7.10%
2020	131,233	$33,592,226	$32,847,443	($4,482,924)	(6.48%)		93,407	$23,909,678	$23,164,895	$5,199,624	7.51%
2021	132,545	$34,267,429	$33,522,647	($4,874,482)	(7.04%)		92,472	$23,907,287	$23,162,504	$5,485,660	7.92%
2022	133,871	$34,956,205	$34,211,422	($5,276,776)	(7.62%)		91,548	$23,904,897	$23,160,114	$5,774,532	8.34%
2023	135,209	$35,658,824	$34,914,042	($5,690,049)	(8.22%)		90,632	$23,902,506	$23,157,723	$6,066,269	8.76%

APPENDIX 12—DSM ANALYSIS USING THE AURORA MODEL

P11 - Balanced 7: CHANGES TO PORTFOLIO FOR DSM ANALYSIS

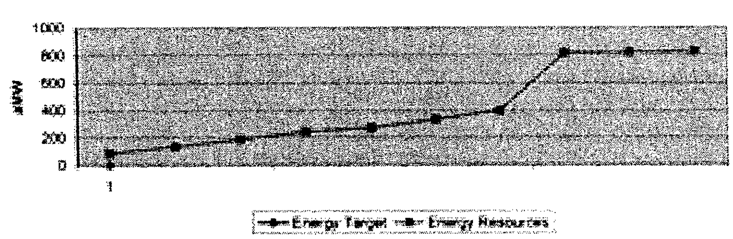
	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Energy Target	66	132	182	236	258	313	412	465	517	511
Capacity Target	54	2	71	163	249	335	429	523	614	706

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Energy	**Increase in Energy with DSM Change**	**0.0**	**1.6**	**4.9**	**4.8**	**13.1**	**17.4**	**21.1**	**24.1**	**26.7**	**29.0**
	Peakers/ mkt purchase for energy	66	130	159	179	99	152	121	0		
	DSM - ALL PROGRAMS	**0**	**4**	**9**	**15**	**21**	**28**	**33**	**38**	**43**	**47**
	100 MW wind 06			20	20	20	20	20	20	20	20
	100 MW wind 07				20	20	20	20	20	20	20
	12 MW CHP 07				12	12	12	12	12	12	12
	100 MW geothermal 08					100	100	100	100	100	100
	150 MW Wind 10							30	30	30	30
	36 MW CHP 10							0	36	36	36
	62 MW Peakers/DG 10							62	62	62	62
	500 MW coal seasonal 11								500	500	500
	Total Energy	66	134	187	245	271	331	397	817	822	826
		0	2	5	9	13	18	-15	352	305	315
Capacity	**Increase in Capacity with DSM Change**	**0.0**	**2.8**	**8.4**	**15.8**	**23.5**	**32.0**	**38.8**	**44.8**	**48.7**	**54.2**
	76 MW DSM A/C & Irrig clipping	0	39	48	57	67	76	76	76	76	76
	DSM - ALL PROGRAMS	**0**	**8**	**18**	**31**	**44**	**56**	**70**	**80**	**92**	**103**
	100 MW Wind 06			5	5	5	5	5	5	5	5
	100 MW Wind 07				5	5	5	5	5	5	5
	12 MW CHP 07				0	12	12	12	12	12	12
	88 MW peaker (2*44) 07				88	88	88	88	88	88	88
	100 MW geothermal 08					100	100	100	100	100	100
	36 MW CHP 10						0	0	36	36	36
	62 MW Peakers/DG 10							62	62	62	62
	150 MW Wind 10							8	8	8	8
	500 MW coal seasonal 11								500	500	500
	Total Capacity	0	47	72	186	321	344	426	973	983	994
		-54	45	1	23	72	9	-4	450	369	288

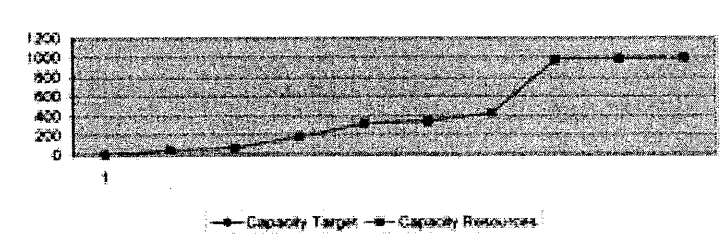
Notes:

1. Peakers can be run to satisfy monthly energy deficit.
2. Market purchases are also available to satisfy monthly energy deficit.
3. Demand response programs are counted as capacity. Energy efficiency and conservation programs are considered to provide energy and capacity.
4. 75 MW of Red Butte - Borah/Brady transmission is available to reduce NW transmission deficit. If coupled with a firm market purchase of up to 75 MW, the NW transmission deficit (and the capacity requirement) can be reduced by the amount of the purchase.
5. PPL Montana contract expires in 2009. This analysis assumes that some form of contract will replace it thus no reduction of capacity occurs in 2010.
6. Wind project output based on 35% CF and seasonal shaping from NW Power and Conservation Council resource characterization paper 5th PP.
7. Decreased capacity target by 80 MW starting in 2010 to account for continuation of Montana purchases.
9. Included wind capacity credit of 5 MW per 100 MW of nameplate capacity - based on July data.
10. Removed "Market Purchase" from description on cells "C17" and "C31", and deleted reference to a 250 MW coal plant in 2009.
11. Revised DSM efficiency programs based on benefit cost ratio's associated with 5_11_05 DSM analysis (programs were change sets to P9).

P11 Balanced 7 - Energy



P11 Balanced 7 - Capacity



IPC Portfolio Analysis - Totals by Year

2004 IRP Final Portfolio (Portfolio 11) with DSM Modifications

AURORAxmp Portfolio Analysis

Portfolio Power Supply Cost Totals without Fixed Carrying Costs

Base Case - P11 as specified in 2004 IRP

Run ID	Condition	Time Period	Name	Item	Energy (MWh)
Base Case	Average	2004	IPC Portfolio	Total	15,096,930
Base Case	Average	2005	IPC Portfolio	Total	15,231,850
Base Case	Average	2006	IPC Portfolio	Total	15,922,790
Base Case	Average	2007	IPC Portfolio	Total	16,230,630
Base Case	Average	2008	IPC Portfolio	Total	16,584,880
Base Case	Average	2009	IPC Portfolio	Total	16,932,760
Base Case	Average	2010	IPC Portfolio	Total	17,352,230
Base Case	Average	2011	IPC Portfolio	Total	17,747,870
Base Case	Average	2012	IPC Portfolio	Total	18,095,100
Base Case	Average	2013	IPC Portfolio	Total	18,407,350
Base Case	Average	2014	IPC Portfolio	Total	18,641,990
Base Case	Average	2015	IPC Portfolio	Total	19,041,670
Base Case	Average	2016	IPC Portfolio	Total	19,527,800
Base Case	Average	2017	IPC Portfolio	Total	19,877,110
Base Case	Average	2018	IPC Portfolio	Total	20,157,440
Base Case	Average	2019	IPC Portfolio	Total	20,506,230
Base Case	Average	2020	IPC Portfolio	Total	20,792,360
Base Case	Average	2021	IPC Portfolio	Total	21,190,330
Base Case	Average	2022	IPC Portfolio	Total	21,559,550
Base Case	Average	2023	IPC Portfolio	Total	21,924,410
Base Case	Average	2024	IPC Portfolio	Total	22,349,890
Base Case	Average	2025	IPC Portfolio	Total	22,665,530
Base Case	Average	2026	IPC Portfolio	Total	23,031,040
Base Case	Average	2027	IPC Portfolio	Total	23,397,920
Base Case	Average	2028	IPC Portfolio	Total	23,816,490
Base Case	Average	2029	IPC Portfolio	Total	24,118,990
Base Case	Average	2030	IPC Portfolio	Total	24,488,310
Base Case	Average	2031	IPC Portfolio	Total	24,883,040
Base Case	Average	2032	IPC Portfolio	Total	25,349,010
Base Case	Average	2033	IPC Portfolio	Total	25,691,800

Case #2: DSM Comm. & Res. Efficiency Programs Increased

Run ID	Condition	Time Period	Name	Item	Energy (MWh)	Cost ($ x 1,000)	Diff. Case #2 - BC
P11 NEW DSM	Average	2004	IPC Portfolio	Total	15,096,930	$ 138,499.90	$ -
P11 NEW DSM	Average	2005	IPC Portfolio	Total	15,231,850	$ 142,795.60	$ (827.60)
P11 NEW DSM	Average	2006	IPC Portfolio	Total	15,922,790	$ 154,539.40	$ (1,422.90)
P11 NEW DSM	Average	2007	IPC Portfolio	Total	16,230,630	$ 131,916.20	$ 3,411.60
P11 NEW DSM	Average	2008	IPC Portfolio	Total	16,584,880	$ 184,997.00	$ (5,260.80)
P11 NEW DSM	Average	2009	IPC Portfolio	Total	16,932,760	$ 195,242.60	$ (8,273.00)
P11 NEW DSM	Average	2010	IPC Portfolio	Total	17,352,230	$ 181,773.60	$ (3,991.80)
P11 NEW DSM	Average	2011	IPC Portfolio	Total	17,747,870	$ 143,970.20	$ (11,419.90)
P11 NEW DSM	Average	2012	IPC Portfolio	Total	18,095,100	$ 161,097.80	$ (12,430.80)
P11 NEW DSM	Average	2013	IPC Portfolio	Total	18,407,350	$ 153,120.60	$ (15,087.70)
P11 NEW DSM	Average	2014	IPC Portfolio	Total	18,641,990	$ 139,139.50	$ (14,979.80)
P11 NEW DSM	Average	2015	IPC Portfolio	Total	19,041,670	$ 151,045.70	$ (16,674.90)
P11 NEW DSM	Average	2016	IPC Portfolio	Total	19,527,800	$ 110,010.90	$ (20,861.30)
P11 NEW DSM	Average	2017	IPC Portfolio	Total	19,877,110	$ 130,688.30	$ (18,501.90)
P11 NEW DSM	Average	2018	IPC Portfolio	Total	20,157,440	$ 72,295.80	$ (15,016.12)
P11 NEW DSM	Average	2019	IPC Portfolio	Total	20,506,230	$ 75,033.98	$ (18,205.82)
P11 NEW DSM	Average	2020	IPC Portfolio	Total	20,792,360	$ 66,857.09	$ (21,880.45)
P11 NEW DSM	Average	2021	IPC Portfolio	Total	21,190,330	$ 129,774.70	$ (21,263.00)
P11 NEW DSM	Average	2022	IPC Portfolio	Total	21,559,550	$ 90,459.85	$ (24,283.15)
P11 NEW DSM	Average	2023	IPC Portfolio	Total	21,924,410	$ 141,027.40	$ (17,059.60)
P11 NEW DSM	Average	2024	IPC Portfolio	Total	22,349,890	$ 63,290.30	$ (22,301.31)
P11 NEW DSM	Average	2025	IPC Portfolio	Total	22,665,530	$ 60,990.96	$ (22,098.54)
P11 NEW DSM	Average	2026	IPC Portfolio	Total	23,031,040	$ 104,097.50	$ (20,538.20)
P11 NEW DSM	Average	2027	IPC Portfolio	Total	23,397,920	$ 199,410.40	$ (18,911.80)
P11 NEW DSM	Average	2028	IPC Portfolio	Total	23,816,490	$ 260,390.50	$ (9,263.70)
P11 NEW DSM	Average	2029	IPC Portfolio	Total	24,118,990	$ 257,182.70	$ (21,269.80)
P11 NEW DSM	Average	2030	IPC Portfolio	Total	24,488,310	$ 287,486.00	$ (24,014.50)
P11 NEW DSM	Average	2031	IPC Portfolio	Total	24,883,040	$ 307,138.90	$ (21,879.90)
P11 NEW DSM	Average	2032	IPC Portfolio	Total	25,349,010	$ 400,123.00	$ (18,379.20)
P11 NEW DSM	Average	2033	IPC Portfolio	Total	25,691,800	$ 440,238.30	$ (20,963.20)

Portfolio Fixed Carrying Costs (Without DSM Fixed Costs)

Year	Base Case: 2004 IRP ($ x 1,000)	Modified Case #2 ($ x 1,000)	Diff. Case #2 -BC
2004	$ 181,865.38	$ 181,865.38	$ -
2005	$ 185,603.99	$ 185,603.99	$ -
2006	$ 204,711.78	$ 204,711.78	$ -
2007	$ 237,451.73	$ 235,153.21	$ (2,298.52)
2008	$ 301,164.19	$ 301,319.77	$ 155.58
2009	$ 289,819.82	$ 289,943.09	$ 123.27
2010	$ 333,387.70	$ 326,076.33	$ (7,311.37)
2011	$ 424,052.32	$ 424,669.72	$ 617.40
2012	$ 413,828.35	$ 414,337.29	$ 508.93
2013	$ 406,729.32	$ 407,219.82	$ 490.50
2014	$ 399,462.22	$ 399,935.34	$ 473.13
2015	$ 392,701.03	$ 393,161.25	$ 460.22
2016	$ 386,552.66	$ 386,999.39	$ 446.73
2017	$ 380,061.65	$ 380,495.15	$ 433.51
2018	$ 373,734.78	$ 374,166.93	$ 432.15
2019	$ 367,443.73	$ 367,870.26	$ 426.53
2020	$ 361,558.05	$ 361,977.63	$ 419.58
2021	$ 355,781.42	$ 356,194.04	$ 412.61
2022	$ 350,023.30	$ 350,428.93	$ 405.63
2023	$ 344,371.48	$ 344,770.11	$ 398.63
2024	$ 340,095.84	$ 340,487.45	$ 391.61
2025	$ 336,825.37	$ 337,209.95	$ 384.58
2026	$ 332,879.68	$ 333,257.21	$ 377.53
2027	$ 329,283.49	$ 329,626.10	$ 342.61
2028	$ 326,084.78	$ 326,407.91	$ 323.13
2029	$ 322,851.79	$ 323,183.60	$ 331.80
2030	$ 319,955.21	$ 320,190.51	$ 235.30
2031	$ 318,457.86	$ 318,646.61	$ 188.75
2032	$ 317,570.21	$ 317,803.47	$ 233.26
2033	$ 443,816.35	$ 445,012.77	$ 1,196.42

DSM Fixed Costs

Year	Base Case: 2004 IRP ($ x 1,000)	Case #2 ($ x 1,000)	Diff. Case #2 -BC
2004	$ -	$ -	$ -
2005	$ 11,777.63	$ 18,473.65	$ 6,696.02
2006	$ 12,169.54	$ 22,816.80	$ 10,647.26
2007	$ 12,858.07	$ 25,693.39	$ 12,835.32
2008	$ 13,522.28	$ 28,582.06	$ 15,059.78
2009	$ 14,326.89	$ 31,140.39	$ 16,813.49
2010	$ 13,154.32	$ 28,484.88	$ 15,330.56
2011	$ 13,468.48	$ 27,860.72	$ 14,392.24
2012	$ 13,790.62	$ 27,715.80	$ 13,925.18
2013	$ 14,119.25	$ 27,717.50	$ 13,598.25
2014	$ 14,590.78	$ 27,984.65	$ 13,393.87
2015	$ 3,790.28	$ 6,607.97	$ 2,817.70
2016	$ 3,838.74	$ 6,244.85	$ 2,406.12
2017	$ 3,888.42	$ 5,972.83	$ 2,084.41
2018	$ 3,939.35	$ 5,863.40	$ 1,924.05
2019	$ 4,099.02	$ 5,994.52	$ 1,895.50
2020	$ 4,151.83	$ 5,925.70	$ 1,773.87
2021	$ 4,206.71	$ 5,877.60	$ 1,670.89
2022	$ 4,262.97	$ 5,859.56	$ 1,596.59
2023	$ 4,320.66	$ 5,917.52	$ 1,596.86
2024	$ 4,547.36	$ 6,102.85	$ 1,555.49
2025	$ 4,557.82	$ 4,557.82	$ -
2026	$ 4,619.97	$ 4,619.97	$ -
2027	$ 4,683.69	$ 4,683.69	$ -
2028	$ 4,749.02	$ 4,749.02	$ -
2029	$ 4,946.06	$ 4,946.06	$ -
2030	$ 5,013.79	$ 5,013.79	$ -
2031	$ 5,084.18	$ 5,084.18	$ -
2032	$ 5,156.35	$ 5,156.35	$ -
2033	$ 5,230.33	$ 5,230.33	$ -

Total Portfolio Power Supply Costs

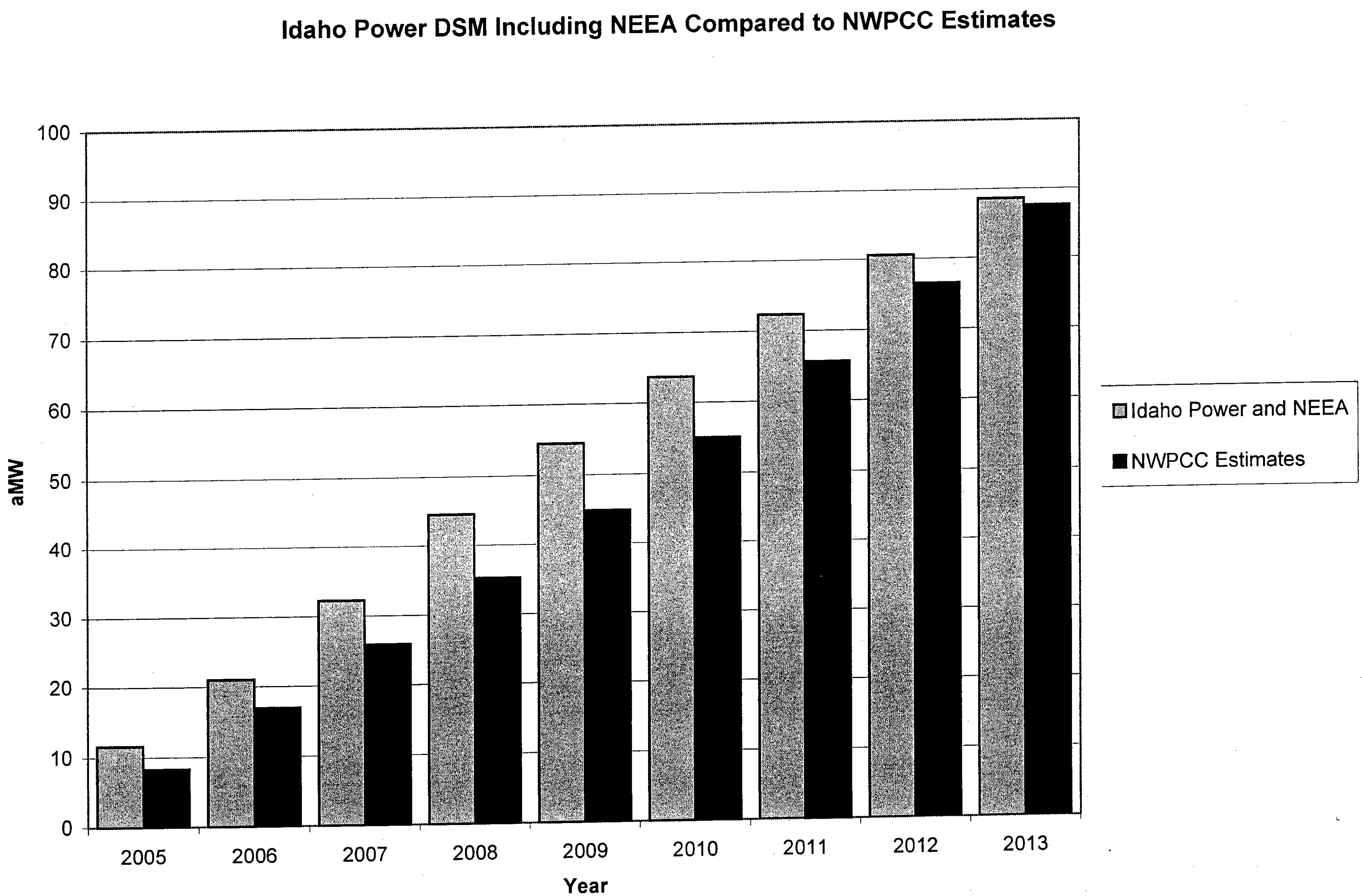
Year	Base Case: 2004 IRP ($ x 1,000)	Case #2 ($ x 1,000)	Difference (Case #2 - Base Case) ($ x 1,000)	Cummulative Present Value of Difference (Case #2 - Base Case) ($x 1,000)
2004	$ 320,365.28	$ 320,365.28	$ -	$ -
2005	$ 340,995.83	$ 346,864.24	$ 5,868.42	$ 5,239.36
2006	$ 372,843.63	$ 382,067.98	$ 9,224.36	$ 12,875.36
2007	$ 378,814.39	$ 392,762.79	$ 13,948.40	$ 23,581.32
2008	$ 504,644.26	$ 514,598.82	$ 9,954.56	$ 30,665.59
2009	$ 527,662.31	$ 536,326.06	$ 8,663.76	$ 36,382.37
2010	$ 532,307.42	$ 536,334.81	$ 4,027.39	$ 38,846.37
2011	$ 592,910.91	$ 596,500.64	$ 3,589.73	$ 40,882.71
2012	$ 601,139.57	$ 603,142.89	$ 2,003.31	$ 41,936.39
2013	$ 594,056.87	$ 593,057.92	$ (998.95)	$ 41,449.23
2014	$ 568,371.30	$ 567,258.49	$ (1,112.80)	$ 40,946.05
2015	$ 564,211.91	$ 550,814.93	$ (13,396.98)	$ 35,329.33
2016	$ 521,263.59	$ 503,255.14	$ (18,008.45)	$ 28,328.92
2017	$ 533,140.27	$ 517,156.29	$ (15,983.98)	$ 22,567.83
2018	$ 464,986.05	$ 452,326.13	$ (12,659.92)	$ 18,337.04
2019	$ 464,782.54	$ 448,898.76	$ (15,883.79)	$ 13,415.32
2020	$ 456,447.42	$ 436,760.42	$ (19,687.00)	$ 7,759.25
2021	$ 511,027.83	$ 491,848.34	$ (19,179.49)	$ 2,650.16
2022	$ 469,029.27	$ 446,748.34	$ (22,280.93)	$ (2,852.99)
2023	$ 506,779.14	$ 491,715.03	$ (15,064.11)	$ (6,302.79)
2024	$ 430,243.81	$ 409,889.60	$ (20,354.21)	$ (10,624.70)
2025	$ 424,472.71	$ 402,758.75	$ (21,713.96)	$ (14,899.67)
2026	$ 462,135.35	$ 441,974.68	$ (20,160.67)	$ (18,579.86)
2027	$ 552,289.39	$ 533,720.20	$ (18,569.19)	$ (21,722.76)
2028	$ 600,688.01	$ 591,747.43	$ (8,940.57)	$ (23,125.81)
2029	$ 606,250.35	$ 585,312.36	$ (20,938.00)	$ (26,172.41)
2030	$ 636,469.50	$ 612,690.30	$ (23,779.20)	$ (29,380.53)
2031	$ 652,560.84	$ 630,869.69	$ (21,691.15)	$ (32,093.88)
2032	$ 744,228.75	$ 726,082.82	$ (18,145.94)	$ (34,198.51)
2033	$ 910,248.18	$ 890,481.40	$ (19,766.78)	$ (36,324.22)
Discount Rate	7.8520%			
NPV	$ 5,760,081.71	$ 5,723,757.49	$ (36,324.22)	
Difference		$ (36,324.22)		
Levelized	$ 523,959.12	$ 520,654.93	$ (3,304.19)	
Difference		$ (3,304.19)		

Notes: * All values averaged over all hours of simulation
Base case includes all existing and committed resources as of January 1, 2004.
Base case includes Portfolio 11 resources and DSM programs as outlined
in IPC's 2004 Integrated Resource Plan (IRP).
All costs nominal.
IRP planning period is 2004 - 2013.
Additional resources have been added to
the IPC portfolio to meet future loads.

Conditions: 70th percentile hydro conditions, 70th percentile loads as specified by 2004 IRP.
Simulation: Every 3rd hour, MWFSu, 1st & 3rd weeks, Jan. 2004 - Dec. 2033
Abbreviations: BC - Base case
IRP - Integrated Resource Plan
Version: AURORAxmp version 7.1.0.0
Revised: November 5, 2004

DSM Targets for 2013
within the Idaho Power Service Territory (aMW)

	Residential	Commercial	Irrigation	Industrial	Total
Idaho Power 2004 IRP	1.6	0.9	5.3	8.7	16.5
Idaho Power 2004 IRP with Increased DSM	15.3	13.9	5.3	8.7	43.2
Increase to 2004 IRP	13.7	13.0	-	-	26.7
NWPCC 5th Power Plan	32.3	29.4	5.8	20.2	87.6
IPCo Percentage of NWPCC	**47%**	**47%**	**93%**	**43%**	**49%**


Idaho Power DSM Including NEEA Compared to NWPCC Estimates
100
90
80
70
60
50
40
30
20
10
0
aMW
2005
2006
2007
2008
2009
2010
2011
2012
2013
Year
Idaho Power and NEEA
NWPCC Estimates

APPENDIX 13—FLIP CHART REGARDING TIM TATUM'S PRESENTATION

Δ Power Supply Costs from Increased Energy Conservation

(Excludes fixed costs, but includes higher levels of DSM—43% total)

1) Reduction in cost every year except year 7 (deferred CHP resource that year)
2) Fixed cost—increases except in 2 years of deferred resource (does not include DSM)
3) What does increasing level of DSM do to power supply costs?
   - By increasing DSM and deferring some CHP resources, shows reduction ($36 million) (now through 2033) in power supply costs. Net benefit does not occur until 2022—would require investment by company.

APPENDIX 14—FLIP CHARTS REGARDING COMMISSION REPORT

Commission Report

I. History of issue that generated work group—IPUC

II. What did work group do?
   - Studies –problems analysis, assumptions, why we did studies we did
   - What mechanisms explored
   - Results of investigation (possible solutions/details)

III. Conclusions and recommendations
   - Questions on wall

IV. Figures and tables, studies, workshop summaries

Report Review

Drafts circulated to all

Replies go to "report coordinator" from parties

- IPC
- NWEC
- Industry
- IPUC

APPENDIX 15—FLIP CHARTS REGARDING QUESTIONS TO ANSWER

Are there financial disincentives to energy conservation?

If there are financial disincentives, where are they (nature) and what is their extent?

What other information do we need?

Bin

1) Is the fixed cost recovery the issue or some other specific way to address DSM?
2) How much lost revenue (recovered) will cause company to do something otherwise?

Are there financial disincentives to energy conservation?

- IPUC—yes (loss of revenue associated with every kWh unsold)
- IPC
- ICIP
- NWEC

If there are financial disincentives, where are they (Nature), and what is their extent?

- In loss/fixed margin associated with unused kWh needed to recover fixed cost set in a rate case.
    - Magnitude of company energy efficiency effort
    - The more effective energy programs are, the less fixed cost lost margin
- Residential and small commercial ratepayers most affected. Rates would affect this.

How much lost revenue (recovered) will cause the company to do something otherwise?

- IPC
    - Re-energizing DSM program
    - Out-of-pocket expenses is bigger concern than lost revenue recovery at this time

Is fixed cost recovery the issue/best way to address DSM

[Cannot be answered at this time]

APPENDIX 16—FLIP CHARTS REGARDING NEXT MEETING AND ACTION ITEMS

What	Who	When
1) Check with commission regarding scope of PBR discussion (DSM related only)	Randy	
2) Talk with Bill about report coordination—reply to Susan to distribute to work group	Nancy	11/09
3) Coordinate timing for the draft report to work group for review/status report	Susan	Next meeting or e-mail
4) Develop PBR strawman well suited for Idaho, done elsewhere	IPUC	Next meeting
5) Complete Analysis For o PBR—IPC–Defer o Refined Cavanagh True-Up	IPUC	Next meeting
6) Refine Cavanagh true-up strawman	Ralph	Next meeting

December 1 meeting (9:30 to 3:30)

- Strawmen presentations
- Evaluation criteria
- Status update

December 13 (alternative or next date)

ASSESSING FINANCIAL DISINCENTIVES AND RESOLUTION OPPORTUNITIES, WORKSHOP #4

DECEMBER 1, 2004, 9:30 A.M. TO 3:00 P.M.
CONFERENCE ROOM 9 EAST, IDAHO POWER CORPORATE HEADQUARTERS, BOISE, ID

Facilitation Susan Hayman, North Country Resources, Inc.
Documentation Natalie Chavez, Chavez Writing & Editing, Inc.

WORKSHOP OBJECTIVES

1) Confirm criteria to evaluate the applicability and desirability of potential mechanisms to remove disincentives/provide incentives for utility investment in DSM programs
2) Review two potential mechanisms:
   a) Refined true-up mechanism
   b) Performance-based ratemaking mechanism
3) Confirm the type of report that will be submitted to the IPUC on December 15 and assignments for preparation and review

WORKSHOP DECISIONS AND OUTCOMES

Participants agreed to a set of evaluation criteria for potential disincentive/incentive mechanisms. The purpose of the evaluation would be to compare and contrast different mechanisms to determine their applicability and desirability.

Participants also decided to recommend a pilot of the performance-based mechanism proposed by IPUC staff for one program until the next rate case. They also want to simulate the true-up mechanism during the same period, based on real numbers, to consider it further and refine the mechanism. The next meeting is scheduled for December 13, 9:00 am to 12:00 pm at IPC to discuss the details of these recommendations. The final report and an application for the pilot program will be submitted to the IPUC some time in January (dates to be determined December 13).

ACTION ITEMS

	What?	Who?	When?
1)	Draft and distribute status report for review and comment	Susan Hayman and Scott Woodbury	December 3
2)	Prepare the outline and anything else necessary for developing the proposal for a pilot performance-based incentive mechanism; bring to the next meeting	IPC (Darlene Nemnich)	December 13
3)	Design the simulation for the true-up mechanism; bring to the next meeting	IPC (Mike Youngblood)	December 13

WORKSHOP INTRODUCTION

Susan Hayman, North Country Resources, welcomed participants (Appendix 1), reviewed workshop objectives (above), and then reviewed the agenda (Appendix 2). She also reviewed posters with the principles of meeting conduct, purpose and products of the workshop series, and important definitions.

MECHANISM EVALUATION CRITERIA

Hayman distributed a handout with potential mechanism evaluation criteria (Appendix 3). She compiled these criteria after telephone conversations with many of the participants prior to the November 8 workshop. Hayman said that the list served as a starting point for developing a final list of criteria against which to evaluate potential disincentive and incentive mechanisms. Participants first clarified their understanding of the criteria, and then revised criteria until they were acceptable to all. Appendix 4 includes flipchart notes taken during the discussion. However, most changes were captured on the wall poster of the preliminary criteria during group discussion. The final revised list is included in Appendix 5.

POTENTIAL MECHANISMS

Refined True-Up Mechanism

Ralph Cavanagh, Natural Resources Defense Council, spoke about the requested revision to the strawman proposal for an Idaho Power true-up mechanism (introduced at Workshop #2 on September 27, 2004). A handout summarized points of the original proposal as well as the proposed revisions (Appendix 6). These proposed revisions included true-up based on actual customer counts for residential and commercial customers (rather than on forecasted sales for all customer classes as originally proposed).

Cavanagh, in cooperation with Idaho Power staff, looked into how often a true-up tied to actual customer counts would have increased or reduced rates for the residential and commercial classes since 1990. For any year during which such a mechanism would have been in effect, rates would have gone down if the class's retail sales had grown more rapidly than the class's customer count, and vice versa. For the commercial sector, electricity use grew more rapidly than the customer count in 10 of the 14 years since 1990. For the residential sector, electricity use grew more rapidly than customer count in 2 of the 14 years, while rates of growth were essentially identical in 3 years (including 2003). These findings confirm the potential for rate decreases as well as increases for both classes under a true-up mechanism, although based on historical data, the likelihood of a rate decrease is substantially greater for the commercial sector than for the residential sector. Cavanagh emphasized that annual class-specific rate increases necessary to ensure recovery of the authorized fixed-cost revenue requirement would never have exceeded 2% under the true-up mechanism. In most years, for both classes, rates would have shifted up or down by 1% or less.

During his presentation, Cavanagh shared the following:

- A bar chart showed the net benefit of expanded energy-efficiency efforts for the Idaho system. The high case indicated the greatest net benefit to the system at just over a $100 million (Appendix 7). Given the net benefits, financial disincentives need to be removed so that Idaho Power is encouraged to promote energy efficiency through conservation programs.
- This true-up mechanism provides symmetry in that it addresses both lost revenues and found revenues. Therefore, it discourages "perverse incentives" and DSM programs that "look good on paper but aren't effective in practice."
- The revised strawman proposal avoids cross subsidies and is fundamentally fair to the customers.
- A second bar chart showed the annual household energy use (in kWh) for entertainment electronics that will likely be typical of households in about 10 years (Appendix7). It's expected that combined energy use for plasma TVs, DVD/VCRs, and set top box/satellite receivers will be about 1,200kWh annually, up from about 500 kWh now with analog TVs. Workshop participants were cautioned through this example that technological advances and changes in customer habits do not necessarily lead to reduced per-customer electricity usage. This underscores the importance of well-designed energy efficiency incentives, as well as and the merits of the revised NRDC true-up proposal (which ties any increases in fixed cost recovery for the residential and commercial classes to increases in the number of residential and commercial customers).
- A performance-based mechanism could be used in conjunction with the true-up mechanism.

Follow-up discussion among participants focused on how big the impacts of implementing a true-up mechanism would be to residential and commercial customers and how rate adjustments would be calculated. Flipchart notes made during this portion of the workshop are included in Appendix 8.

Performance-Based Ratemaking Mechanism

Lynn Anderson, IPUC, distributed a two-page strawman proposal for a performance-based mechanism (Appendix 9). Before talking about the proposal summarized on the second page, he asked that participants review the hypotheses included on the first page. Until he compiled this list, he had been unable to draft the proposed mechanism. The following issues were raised during discussion of hypotheses:

- Cavanagh questioned the exclusion of increased gas market share from fixed-cost losses in hypothesis #7. Idaho Power may be motivated to retain electric market share for water heaters if the company is unable to recover the fixed-cost revenue losses resulting from customers' conversion to more efficient gas water heaters. This approach seems to penalize the company for these conversions and encourage inefficiency. IPUC staff pointed out that Idaho Power could implement a DSM program that reimburses customers for converting to energy-efficient gas water heaters.
- Some workshop participants see some inconsistency in the IPUC's view on factors outside Idaho Power's control. For example, the strawman proposal disallows Idaho Power from collecting fixed-cost revenue losses unless incurred through DSM efforts. Yet reimbursement of fuel costs through the company's Power Cost Adjustment (PCA) mechanism does allow for factors outside the company's control.
- The means for verifying savings resulting from DSM programs are likely to be "complex, tedious, and expensive."

Following discussion of the hypotheses, Anderson explained the actual proposal, found on the second page of the handout. The IPUC staff's strawman proposal would implement a mechanism to remove financial disincentives by allowing specific fixed-cost revenue recovery for all verified DSM savings with a bonus financial incentive for exceeding cost-effective DSM targets. He pointed out that the financial incentives component of the proposal could also be implemented as a stand-alone approach or with a true-up mechanism. This mechanism, as proposed, would be implemented as a trial restricted to the Residential New Construction program. Residential energy rates have a relatively high fixed-cost recovery component, which means that Idaho Power's financial disincentive for DSM in this class may be higher than for other customer classes. It's also a relatively small program, so effects of any mistakes made in the trial would be minimized. The following points were made during discussion of the performance-based proposal:

- According to Darlene Nemnich, IPC, Idaho Power rewards customers $750 when they exceed building code on energy efficiency by 30% on new construction. Ideally, builders would want to make homes as energy efficient as possible, but they are unlikely to want to change codes. Therefore, code enforcement and training of code officials is important, and it is reasonable to credit utilities with work they do with code enforcement beyond typical DSM programs.
- Because of the trial nature of the mechanism, no penalties are included. Quality control is relatively straightforward, and the targeted customer group is narrow, but the potential for perverse incentives cannot be dismissed.

Flipchart notes pertaining to the performance-based mechanism are included in Appendix 10.

Additional Suggestion

David Hawk, J.R. Simplot Co., suggested that the group conduct an 18-month simulation of the two proposed mechanisms based on real numbers. He believed that all parties and participants had invested too much time discussing concerns with financial disincentives and potential corrective mechanisms for nothing to happen. Because participants may not be comfortable implementing one or both of the proposed mechanisms right now, an 18-month simulation would allow proposals to be studied further and problems worked out before the group forwarded a firm recommendation to the IPUC. The flipchart regarding Hawk's suggestion as well as other modeling options is included in Appendix 11.

NEXT STEPS

Mechanism Analysis/Evaluation

Ric Gale, IPC, requested that the interest groups (IPUC, Idaho Power, Northwest Energy Coalition, and Industrial Customers) caucus before presenting their views on each of the three proposals: true-up mechanism, performance-based pilot, and 18-month simulation of the two proposals. Hayman allotted 15 minutes for caucusing. Afterwards, she asked that group spokesmen share their groups' views on the three proposals and next steps. Industrial Customers felt that David Hawk's previous suggestion for a simulation adequately represented their view. Flipchart notes from the three interest reports are included in Appendix 12.

Idaho Power Company

Gale reported the following Idaho Power perspectives regarding the proposals:

- Idaho Power is concerned about disallowance of program costs. The company endeavors to manage program costs as effectively as possible. But disallowance of program costs and prudence reviews by the IPUC significantly deters DSM investment.
- In the intermediate or long term, the company may want to implement a true-up mechanism. In the next couple of years, Idaho Power wants to undertake the activities in the IRP but is probably unable to ramp up DSM any more than that. They are, however, amenable to simulating the true-up mechanism until the next rate case to at least identify unintended consequences. Gale isn't sure how much influence results of the simulation will have, but it could eliminate a degree of the uncertainties.
- The company is intrigued by IPUC staff's incentive mechanism and supports piloting it with one program until the next rate case and then evaluating its applicability to others.

Northwest Energy Coalition

Ralph Cavanagh shared the following viewpoints for Northwest Energy Coalition representatives:

- They are not convinced that a simulation will change people's minds. Therefore, the coalition isn't interested in pursuing a simulation unless the group is truly committed to moving forward, the simulation/test is credible, and the exercise establishes an architecture that can be used in the next rate case.
- The simulation may or may not be effective in evaluating how Idaho Power Company's appetite for conservation programs would change if a true-up were implemented. Rather, the simulation will give an indication of the rate impact of the true-up under hypothetical scenarios of conservation activity.
- Their commitment to the true-up mechanism hasn't diminished. Although they can forward the proposal directly to the IPUC, they prefer to continue working with this group. Gale commented that the simulation allows the group to refine the mechanism before the next rate case so that they can give the IPUC something feasible.

Idaho Public Utilities Commission

Randy Lobb reported the following points of view for IPUC representatives:

- They understand Idaho Power's concern about cost recovery and prudence reviews. But the IPUC will continue these reviews, and the company will likely continue to do a good job. They believe that, because of the Energy Efficiency Advisory Group (EEAG), the company is actually at less risk now regarding disallowances than it has been in the past.
- The IPUC is interested in piloting the performance-based mechanism on a single program. This pilot allows everyone to see whether the complexity can be worked out and the mechanism is feasible.
- The IPUC is also amenable to the 18-month simulation of the true-up mechanism if the other groups support it. The main purpose of the mechanism is to see how it changes company activities. A simulation may have some value. If nothing else, it keeps a mechanism that the IPUC staff is unlikely to suggest adopting at the moment on the table for future consideration. Working through it now may

provide the company information it needs when it starts making decisions for the next two-year IRP cycle.

Commission Reports and Timelines

Hayman directed participants to discuss the two reports—status and final—to the IPUC and timelines for continued activities. The following decisions were made:

- Scott Woodbury, IPUC, and Hayman will collaborate on the status report and send it out Friday, December 3, for review.
- This group will meet Monday, December 13, to discuss details of the pilot performance-based mechanism and simulation of the true-up mechanism.
- Idaho Power staff will prepare an outline for the pilot program and a design for the simulation for discussion and finalization at the December 13 meeting. The company would like to see the pilot start January 1 (or as soon as possible thereafter) when the DSM program begins. The pilot application does not have to be submitted with the final report, although the report will be supportive of the filing. The group agreed that the final report may precede the application filing unless they were submitted concurrently. The group decided to talk specifically about the timing of the filing and the report at the December 13 meeting.
- Bill Eddie, Advocates for the West, will coordinate the final report, which will likely be a recommendation to implement the pilot and simulation until the next rate case. The draft outline for the report was developed at the November 8 meeting.

WRAP-UP AND WORKSHOP EVALUATION

Hayman reviewed action items to be completed before the next workshop (Appendix 13). This workshop is scheduled for December 13, 2004, from 9:00 am to 12:00 pm. Mike Youngblood agreed to check on the availability of Conference Room 9 East for this workshop. During the workshop, participants will discuss details of the pilot performance-based mechanism and simulation of the true-up mechanism.

Hayman also requested that participants evaluate the workshop. She recorded positive items and possible changes on flipcharts (Appendix 14). Though feelings were mixed on preferable room size and temperature, for the most part, participants are pleased with the honest and frank discussion, facilitation and documentation, and refreshments.

APPENDIX 1—PARTICIPANTS

(Shading indicates work group participants unable to participate in person or by phone.)

Name and Affiliation	Name and Affiliation
Lynn Anderson, IPUC	Laura Nelson, IPUC
Maggie Brilz, Idaho Power	Darlene Nemnich, Idaho Power
Terri Carlock, IPUC	Peter Richardson, Industrial Customers of Idaho
Ralph Cavanagh, Natural Resources Defense Council	Brad Purdy, Community Action Partnership Association of Idaho
Bill Eddie, Advocates for the West	Don Reading, Ben Johnson Associates
Ric Gale, Idaho Power	Greg Said, IPC
David Hawk, J.R. Simplot Co.	David Schunke, IPUC
Nancy Hirsh, NW Energy Coalition	Tim Tatum, Idaho Power
Bart Kline, Idaho Power	Mike Youngblood, Idaho Power
Randy Lobb, IPUC	Scott Woodbury, IPUC

APPENDIX 2—AGENDA

ASSESSING FINANCIAL DISINCENTIVES AND RESOLUTION OPPORTUNITIES WORKSHOP #4

December 1, 2004
9:30am-3:00pm
Conference Room 9 East
Idaho Power Corporate Headquarters
Boise, Idaho

Objectives:

1) Confirm criteria to evaluate the applicability and desirability of potential mechanisms to remove disincentives/provide incentives for utility investment in DSM programs
2) Review two potential mechanisms:
   a. Refined true-up mechanism
   b. Performance-based ratemaking mechanism
3) Confirm the type of report that will be submitted to the IPUC on December 15, and assignments for preparation and review

Final Agenda
(breaks will be taken when most convenient for the group)

Time	Topic	Process
9:15am	*Coffee/Tea available in meeting room*	
9:30am	**Welcome/Introductions/Meeting Overview** – Susan Hayman	Information
9:45am	**Mechanism Evaluation Criteria** – Susan Hayman	Exercise / Discussion
10:30am	**Potential Mechanism** ▪ Refined true-up mechanism – Ralph Cavanagh	Presentation / Discussion
11:30pm	**Lunch** (on your own)	
12:30pm	**Potential Mechanism** ▪ Performance-based ratemaking mechanism – Lynn Anderson	Presentation / Discussion
1:30pm	**Next Steps** – Group ▪ Mechanism analysis/evaluation to be completed (using criteria, other?) ▪ Nature of the December 15 IPUC report ▪ Timelines	Discussion
2:45pm	**Wrap-up and Evaluation** – Susan Hayman	Discussion
3:00pm	**Adjourn**	

Potential Mechanism Evaluation Criteria

1) Balanced (fair) allocation of program costs across shareholders and ratepayers
2) Cross-subsidization of program costs across ratepayer groups are minimized
3) Removes financial disincentives to the max
4) Positive financial benefit (at least less negative effect), measured over time
5) Ratepayers are better off than they would be without the mechanism
6) Promotes rate stability
7) Simple mechanism
8) Costs easily tractable
9) Mechanism adjustments are predictable and easily understood
10) Monitors short and long term effects to customers and company
11) Incentives to manipulate the mechanism are not present
12) Close link between mechanism and desired DSM outcomes
13) Provides adequate incentive for the acquisition of all cost-effective DSM

APPENDIX 4—FLIPCHARTS REGARDING EVALUATION CRITERIA

Criteria

#4 Needs clarification

- "Benefit to all stakeholders from where they would have been otherwise"
- Drop "less negative"—should be net benefit

#10 Process needs to monitor mechanism

"Ratepayers" are "customers" [change throughout]

#8 Tractable

- Want mechanism that is affordable
- Costs known and manageable, not subject to unexpected fluctuations
- not talking about program cost recovery

#5 Difficult to know benefits to all stakeholders until after the fact

- #5 is the bottom line

#11 Avoid "perverse" incentives

Stakeholder =

company and customers

includes everybody

Potential Mechanism Evaluation Criteria

1) Stakeholders are better off than they would be without the mechanism
2) Minimize cross subsidies across customer classes
3) Removes financial disincentives
4) Optimizes the acquisition of all cost-effective DSM
5) Promotes rate stability
6) Simple mechanism
7) Administrative costs and impacts of the mechanism are known, manageable, and not subject to unexpected fluctuation
8) Monitors short and long term effects to customers and company
9) Avoids perverse incentives
10) Close link between mechanism and desired DSM

APPENDIX 6—REVISIONS TO THE STRAWMAN PROPOSAL FOR AN IDAHO POWER TRUE-UP MECHANISM

PROPOSED REVISIONS TO STRAWMAN PROPOSAL FOR AN IDAHO POWER TRUE-UP MECHANISM

Submitted by Ralph Cavanagh
For discussion at 12/1/04 workshop

I. ORIGINAL PROPOSAL, DISCUSSED AT 9/22/02 WORKSHOP

1. Starting point: fixed-cost revenue requirement and retail rates approved by Idaho PUC in latest Idaho Power rate case.

2. If, after initial year, changes in retail electricity use lead to under- or over-recovery of fixed cost revenue requirement, a rate true-up would occur in the following year on the same schedule as the Company's current Power Cost Adjustment.

3. Until reestablished in the next Idaho Power rate case, the currently approved fixed cost revenue requirement would be automatically adjusted annually to reflect the same rate of increase (or decrease) shown for retail electricity sales, net of any DSM programs, in Idaho Power's latest IRP. True ups would occur annually based on any divergence between the total fixed-cost revenue recovery that forecast sales would have delivered and the fixed-cost revenues actually recovered (so if, for example, sales were forecasted to increased by 2 percent and actually increased by a larger percentage, Idaho Power would refund the difference at the time of the next Power Cost Adjustment; if retail sales increased by a smaller percentage than forecast, Idaho Power would get back the lost revenues at the time of the next Power Cost Adjustment).

4. True-ups would occur by customer class based on divergence between actual and forecast sales to each customer class.

5. Idaho Power would continue to absorb the risk or benefits of purely weather-related effects on fixed-cost revenue recovery, as it does now. This would mean weather normalizing actual sales before making the annual true-up calculation.

MAXIMUM ANNUAL AVERAGE RATE IMPACT OF THE TRUE UP MECHANISM, UP OR DOWN, UNDER EXTREME CONDITIONS = 1.5 PERCENT.

II. PROPOSED REVISIONS AND ANSWERS TO SUBSEQUENT QUESTIONS

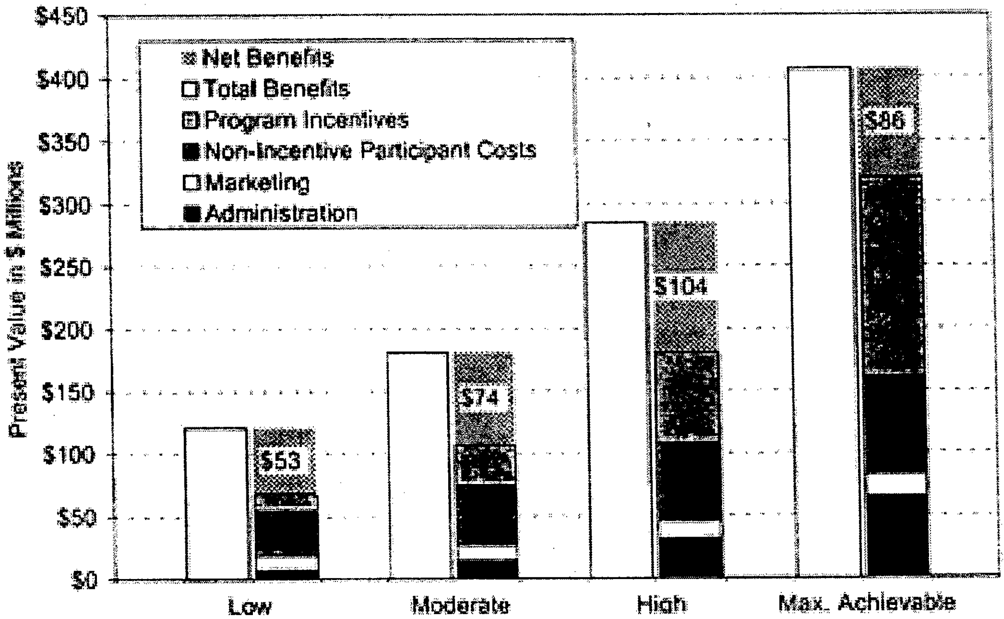
A. **CHANGES IN CALCULATION OF ANNUAL FIXED COST RECOVERY:** Without a true-up, fixed cost recoveries grow in direct proportion to growth in total retail sales, averaging about 2 percent per year over the past decade. The initial proposal called for growth in fixed cost recovery to be tied to annual growth in the forecast of retail sales adopted in the Company's most recent IRP. Concerns were raised that, in the residential and commercial sectors particularly, growth in customer counts could substantially exceed growth in forecast sales, resulting in underrecovery of costs prudently incurred to serve new customers. PROPOSED SOLUTION: Tie growth in fixed cost recovery to actual measured changes in annual customer count for the residential and commercial sectors. This should allow a closer convergence between the fixed cost revenue requirement and actual costs of service.

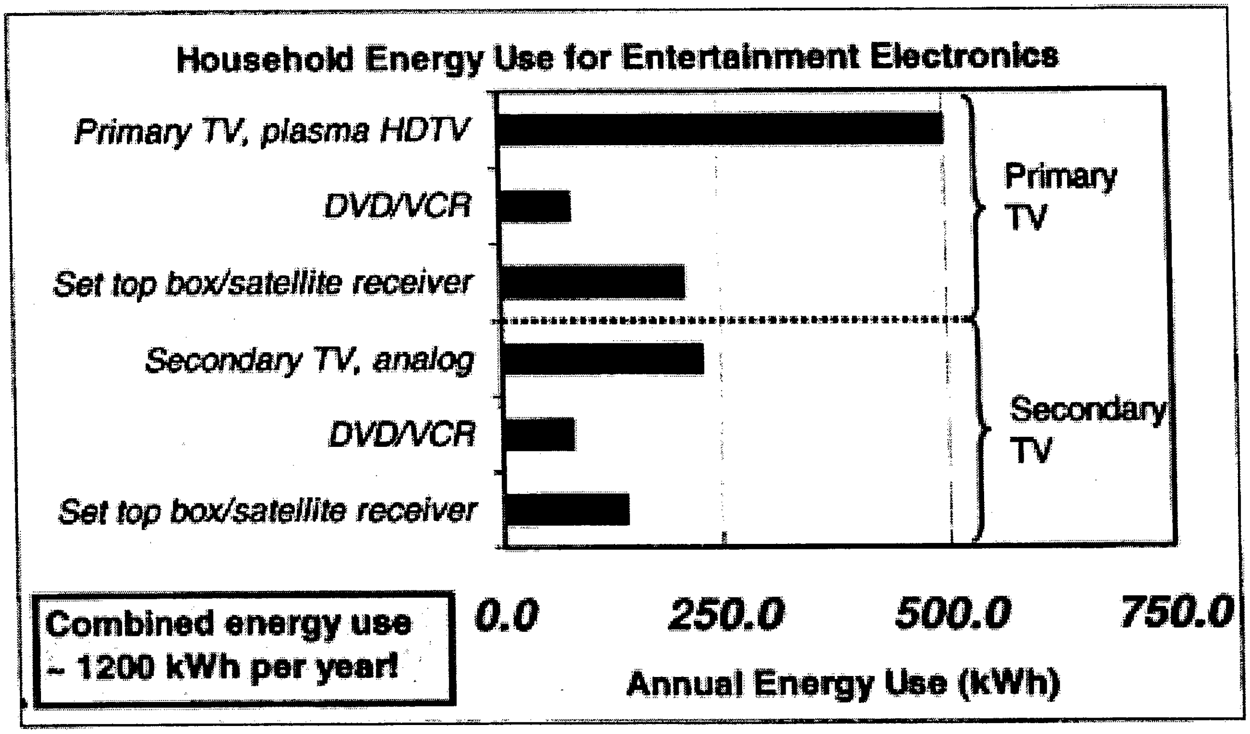
B. **RETROSPECTIVE ASSESSMENT:** In cooperation with the Company, I looked into how often a true-up tied to customer counts would have increased and reduced rates, respectively, for the residential and commercial classes since 1990 (concerns had been raised that rates would always go up under such a mechanism). For any year during which such a mechanism had been in effect, rates would have gone down if the class's retail sales had grown more rapidly than the class's customer count, and vice versa. So we looked at how often the residential and commercial customer counts increased more rapidly than class-wide electricity use in each year, starting in 1990. For the commercial sector, electricity use grew more rapidly than the customer count in ten of the fourteen years from 1990-2003. For the residential sector, electricity use grew more rapidly than customer count in two of the fourteen years, and the rates of growth were essentially identical in three other years (including 2003). This confirms the potential for rate decreases as well as increases for both classes under a true-up mechanism, although based on historical data the likelihood of a rate decrease is substantially greater for the commercial sector than the residential sector. Finally, it should be emphasized that annual class-specific rate increases needed to ensure recovery of the authorized fixed-cost revenue requirement would never have exceeded two percent under the true-up mechanism. In most years, for both classes rates would have shifted up or down by one percent or less.

APPENDIX 7—BAR CHARTS DISTRIBUTED BY CAVANAGH

Exhibit ES-5

Present Value Costs and Benefits – Achievable Potential Scenarios





APPENDIX 8—FLIPCHARTS REGARDING CAVANAGH'S REVISED STRAWMAN

Assumptions for True-Up

- Last year's consumption plus 2% to calculate the rate increase spread over kWh the next year.
- "Clear every year"—don't want to carry significant over/underages/year
- If kWh sales exceed customer count in a class, there would be a rate decrease.
- Question: How to resolve true-up within schedules for irrigators and industrial? [how to true-up with subclasses to the classes]
- Rate impacts could be more volatile under multiple true-up values

APPENDIX 9—PROPOSED STRAWMAN FOR A PERFORMANCE-BASED MECHANISM

Strawman Proposal for DSM Performance Incentive

For Discussion at IPC Decoupling Workshop, 12/01/04

Hypotheses:

1) The primary DSM financial disincentives in question are those that affect shareholders, rather than managers. These disincentives are primarily "fixed-cost" revenues that are not collected when electricity is not sold; i.e. those portions of energy and demand prices that are based upon utility costs that do not vary with energy usage in the short run.

2) Idaho Power will fail to maximize demand-side management (DSM) potential benefits for its customers unless the primary financial disincentive is removed through a regulatory mechanism.

3) Idaho Power's customers will be net beneficiaries if the company provides more cost-effective DSM as a result of customers paying to remove the primary financial disincentive.

4) Rate cases will occur too infrequently to sufficiently mitigate the primary financial disincentive.

5) The company is legitimately entitled to recover fixed-cost revenue losses caused by its DSM efforts regardless of the absence of rate case examination of overall costs and revenues.

6) Idaho Power is incurring new fixed costs due to customer growth and its incremental fixed costs exceed its incremental fixed-cost revenues. In other words, customer growth does not mitigate fixed-cost revenue losses.

7) It is unacceptable to the IPUC Staff to adopt a financial mechanism that would simply allow Idaho Power, without a rate case, to automatically collect <u>all</u> "fixed-cost losses" associated with <u>all</u> kWh per customer sales reductions, much of which is caused by factors not associated with the company's DSM, e.g. increased gas market share. The 10-year lapse between Idaho Power's last two rate cases, in spite of reduced sales per customer, is an indicator that profitability is largely independent of sales per customer.

8) It is unacceptable to Idaho Power to adopt a financial mechanism that considers only total sales; i.e. that does not account for growth in the number of customers.

9) Removing the primary financial disincentive for DSM can be reasonably accomplished through a mechanism that targets only DSM-caused sales reductions. There are two ways to do this: a) The financial disincentive could be removed by allowing specific fixed-cost revenue recovery for all verified DSM savings; b) The financial disincentive could be removed by providing other financial rewards for verified DSM accomplishments. Method b)'s financial rewards could be stand-alone or used in conjunction with method a) or with decoupling.

Strawman Trial Proposal

Unlike decoupling, both methods a) and b) above require precise measurement and verification of DSM program implementation details, baselines and DSM results, and, as such, are inherently complex, subject to measurement error, and require significant regulatory oversight. Thus, it is reasonable to implement either of these methods on a trial basis.

For a strawman trial, we have selected a proposal that combines methods a) and (b) above; i.e. recovery of DSM-caused fixed-cost revenue losses with a bonus financial incentive for exceeding cost-effective DSM targets. We suggest that the trial be restricted to the Residential New Construction program. Residential energy rates have a relatively high fixed-cost recovery component, which means that Idaho Power's financial disincentive for DSM for this class may be higher than for other customer classes. This is a comparatively small program, thus minimizing the effects of any mistakes made in the trial. Nevertheless, this program is projected to be very cost-effective for both energy and peak demand savings and "lost opportunity" will occur if it is not vigorously pursued.

The table below illustrates some of the projections for the Residential New Construction program as contained in the IRP. Also shown are discussion starting points for financially rewarding Idaho Power for significantly outperforming its projections. Whatever combination of indicators and incentives are used, the program must remain cost effective to customers.

Possible Indicators	Annual Targets	Fixed-Cost Rev. Recovery	e.g. Bonus Threshold	Bonus Financial Incentive (for illustration only)
MW reduction	0.19	n.a.	10% > target	20% of net $ savings
MWh reduction	1,661	actual MWh saved x $31.20	10% > target	10% of net $ savings
Idaho Power $/peak kW	5.30	n.a.	10% < target	5% of program costs
Idaho Power $/kWh	0.036	n.a.	10% < target	5% of program costs
Total Resource $/peak kW	8.50	n.a.	10% < target	5% of total costs
Total Resource $/kWh	0.058	n.a.	10% < target	5% of total costs
Participant Payback	6.5 yr.	n.a.	10% < target	5% of participants' costs
Number of Participants	?	n.a.	10% > target	5% of program costs
Market Transformation	?	n.a.	?	5% of program costs

APPENDIX 10—FLIPCHARTS REGARDING PERFORMANCE-BASED MECHANISM

PBR/Hypothesis Discussion

1) Managers = utility company managers
2) This proposal does not address "found" revenues and has a narrow view of "lost" revenues (DSM-related only)
3) #7 Concern about not linking advantages of true-up with issues about increased gas market share

   Staff wants fixed-cost recovery for DSM-related programs (utility co. control) → NOT consensus with group on this

4) Energy savings calculations would be difficult and problematic
5) Cost recovery may be a bigger issue than lost revenues
6) Proposal is for residential construction only (Energy Star program—exceeding building codes)
7) Some potential for perverse incentives—need to monitor closely

APPENDIX 11—ADDITIONAL SUGGESTIONS

Bin

1) 18-month financial simulation of proposals—real, documented numbers for FCR

Options

1) Model period of 10 years
   a) "Council level" of conservation against IPUC staff proposal
   b) True-up with "Council levels" of conservation

- Use maximum net benefit scenario:
  - rate impacts
  - IRP baseline

APPENDIX 12—INTEREST REPORTS

Interest Reports

IPC

1) Disallowance of program costs will kill DSM—first and foremost disincentive
2) Problem of lost revenues will have a…material impact on amount of load-reducing activities we undertake in short and long term
3) Next couple years, company will undertake DSM identified in IRP—can't take on any additional in this period (ramp-up ability limited)
4) 18-month simulation of T.U. mech. would help relieve uncertainties (unintended consequences) prior to next rate case
5) Intrigued with staff incentive mechanism, and piloting with one program then determining applicability to others

NWEC

1) Not convinced simulation will change minds—not interested in pursuing unless group is really committed to moving forward and simulation/test is credible with everyone and materially improve likelihood of approval by Commission
2) Retain right to bring proposal to Commission directly, but would rather work as a group

IPUC—Staff

1) Staff will continue cost-effectiveness/ prudence review
2) Interested in pilot incentive based program. Can work on measurement and evaluation to see if doable.
3) 18-month simulation—main impact of T.U. mechanism is to see how it changes company's behavior. Wouldn't oppose proceeding with this, though unsure of real value of simulation. May be best we can do now to keep alive without killing it.

APPENDIX 13—NEXT STEPS AND ACTION ITEMS

Next Steps

1) Status report on 15th
2) Flesh out concept of pilot and simulation on 13th (9:00–Noon)
3) Provide full report in January with recommendation, what we discussed and why we're proposing this approach. Decision at end point.
4) IPC would submit application for pilot to commission—projected date by end of January (simultaneous with filing or at least final report first)
5) Assuming model can be set up, could possibly start accounting after first of year (January 1 if possible)

Action Items

What	Who	When
1) Draft status report for review and comment	Scott and Susan	12/03/04
2) Bring what is necessary for pilot proposal—outline for filing	IPC (Darlene)	12/13/04
3) Bring simulation design	IPC (Mike)	12/13/04

APPENDIX 14—WORKSHOP EVALUATION COMMENTS

+	ρ
1) Good job!	1) Room is too small and too warm
2) Frankness of conversation useful & appreciated	
3) Like smaller room	
4) Like facilitating	
5) Like someone "ramrodding it"	
6) Appreciate deadlines and follow-up	
7) First class job	

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8) Like smaller room	
9) Like fruit!	
10) Like summaries—timely and well-structured	
11) Nice to get prework discussion items ahead of time	
12) Very important that everyone is here—adds to the process	

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13) Appreciate cheese and celery!	
14) Appreciate comprehensive summaries	
15) Enjoyed open and honest discussion, and movement in positions	
16) Like follow-up with meeting summary—that it is right	